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FEASIBILITY OF PRODUCING COMMODITIES AND ELECTRICITY FOR SPACE SHUTTLE OPERATIONS AT VANDENBERG AIR FORCE BASE

by

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ABSTRACT

Under an interagency agreement with the United States Air Force (USAF), the Environmental Protection Agency (EPA) contracted Radian Corporation to analyze the technical and economic feasibility of the on-site production of commodities (liquid propellants and gases) and electricty to support space shuttle launch activities at Vandenberg Air Force Base. This document is the final project report of this preliminary screening study.

Both commercial and developing systems were considered. Systems to supply electricity were considered to meet continuous electricity demands only, critical launch demands only, or both continuous and critical launch demands. In addition to systems to supply commodities only, several systems to produce both commodities and electricity were considered. All systems were evaluated in the areas of technical risk, conversion efficiency, environmental impacts, reliability, and economics.

A major finding is that over the near term (1992 to 2013) Vandenberg Air Force Base cannot produce electricity at a price competitive with purchased electricity. Also, unless hydrogen markets on the West Coast fundamentally change, there is no incentive to produce liquid hydrogen (the commodity of primary interest) on-site at Vandenberg. These and other findings were used to recommend possible follow-up actions to the USAF.

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Section 1

INTRODUCTION

Under an interagency agreement with the United States Air Force (USAF), the Environmental Protection Agency (EPA) contracted with Radian Corporation to analyze the technical and economic feasibility of the on-site production of commodities and electricity to support space shuttle launch activities at Vandenberg Air Force Base (VAFB). This document is the final project report of the feasibility study.

1.1 BACKGROUND

Since the early 1970s, the National Aeronautics and Space Administration (NASA) has conducted a number of studies directed at reducing the cost of electrical power and commodities (liquid propellants and gases) required for operating the space shuttle. These studies have concluded that the optimum approach for NASA at the Kennedy Space Center (KSC) is the use of a "polygeneration" plant to simultaneously produce liquid hydrogen (LH_2), gaseous nitrogen (GN_2), and electrical power using a coal gasification based energy complex. The last study conducted by NASA (1-1) determined that an on-site plant which features coal gasification could be justified because of its positive effects on the economics, reliability, and availability of electrical power and commodities. The plant at KSC would support nominally 18 shuttle launches annually and would generate more than 30 MW of electrical power for export by KSC. Given the positive results of NASA's studies for on-site production at KSC, the USAF became interested in considering NASA's KSC polygeneration concept for use at VAFB. In recognition of differences between KSC and VAFB, the USAF was interested in evaluating alternatives to the KSC polygeneration concept as well.

While the USAF, like NASA, is also concerned about the costs of commodities and electrical power at VAFB, it is very interested in securing reliable electrical power to support the on-time launch of space shuttles. Currently, in the event of a major power loss, the existing backup power system at VAFB allows for orderly shutdown of launch operations only. It does not provide the power necessary to continue actual launch operations. To support the on-time launch of space shuttles, larger backup systems are needed. To guarantee on-time launches, the USAF has determined that support systems (such as the electrical power supply) must have reliabilities of 99.9999 percent. The current primary electrical power supply, with its reliability of 99.998 percent, is unable to meet the stringent reliability constraint of the launch on-time requirement. (And this current grid reliability may decrease in the future if the utility reserve margins decrease.)

Based on an analysis of the overall system reliability requirement and the existing grid reliability, the backup power supply would need to have a reliability of 95 percent to meet the launch-on-time reliability constraint. If the grid power reliability decreases, the required reliability of the backup power system will be greater than 95%. Several in-house USAF studies have been conducted to determine the most cost effective ways of providing backup power to the existing system. But as yet, definitive specification of a backup power system has not occurred.

With this background, the two-fold purpose of this study was as follows. Based on the results of the NASA/KSC studies, the USAF was interested in evaluating the technical and economic feasibility of on-site options for producing commodities and power. At the same time, to ensure the on-time launch of space shuttles, the USAF was interested in further consideration of backup power systems, either used alone or used as part of continuous power/commodity production systems. After evaluating production options, the best systems were to be identified by considering technical risk, conversion efficiency, environmental impacts, reliability, and economics.

1.2 SCOPE

The level of effort in this feasibility study was that of a "screening" or preliminary study. While the scope used was sufficient to determine the basic feasibility of on-site options for producing commodities and power, more definitive studies would be needed to justify the selection of one of the options for use at VAFB. The following scope describes the basic activities of this screening study:

- VAFB and SLC-6 (Space Launch Complex 6) energy and commodity needs were determined,
- Environmental constraints, control requirements, and permitting issues and requirements were evaluated,
- Energy and commodity price forecasts for VAFB were developed,
- Commodity transportation issues were identified and evaluated,
- Production technology options were identified and characterized,
- First order or preliminary economic analysis of the production technology options was performed, and
- Production options were compared and the best candidates for VAFB were identified for further consideration and study.

Each of these activities is described in a separate section of this report. The study covers the period from 1992 (the year presumed for the startup of on-site plants) to 2013 (the presumed end of the useful life of on-site plants).

1.3 CONCEPTS AND SYSTEMS CONSIDERED

Initially, a large number of concepts, both commercial and undeveloped, were identified as candidates for analysis in this project (see Table 1-1). However, many of these concepts were obviously not practical and thus were

TABLE 1-1. CONCEPTS CONSIDERED INITIALLY

Resources

- Oil
- Natural Gas
- Coal
- Wind
- Water
- Geothermal
- Wood
- Refuse
- Agricultural Wastes
- Oil Shale
- Tar Sands
- Refinery Products
- Spent Solvents
- Ocean
- Nuclear
- Solar

Technologies for Conversion, Generation, or Production

- External Combustion (Boilers)
- Steam Turbines
- Gas Turbines
- Combined or Binary Cycle Turbines
- Internal Combustion (Diesel or Stirling engines)
- Gasification
- Liquefaction
- Partial Oxidation
- Steam Reforming
- Electrolysis
- Air Separation
- Solar Central Receivers
- Solar Photovoltaics
- Wind Turbines
- Fuel Cell
- Hydroelectric Generation
- Ocean Thermal
- Ocean Wave, Tidal, Current
- Magnetohydrodynamics
- Nuclear Fission, Fusion
- Cogeneration
- Polygeneration

Technologies for Storage

- Pumped Hydro
- Compressed Air
- Metal Hydrides
- Flywheel
- Battery
- Conventional Cryogenics
- Other Conventional Fuel
- Magnetic
- Phase Change

excluded from further analysis. The concepts which passed this first screening and were thus further considered are identified in Table 1-2. Concepts which failed this first screening and were thus excluded from further analysis are identified in Table 1-3; reasons for eliminating each concept from further consideration are also given in Table 1-3. Specific production systems selected for study (and based on the concepts in Table 1-2) are idenidentified in Tables 1-4 through 1-6. Table 1-4 identifies the electricity production systems used to meet continuous demands, critical launch demands, or both continuous and critical launch demands. Table 1-5 identifies the systems used to supply commodities. And Table 1-6 identifies the systems used to produce both electricity and commodities.

1.4 ORGANIZATION OF REPORT

This report is organized into eight major sections and two appendices. Section 2 presents the conclusions and recommendations of this study. Section 3 identifies the energy and commodity requirements of VAFB and SLC-6. Section 4 discusses the environmental constraints and considerations at VAFB. Section 5 presents the energy and commodity price forecasts through 2010. Section 6 discusses commodity transportation issues. Section 7 presents technical and economic characterization of the candidate production systems. Section 8 evaluates and ranks the various candidate systems. Appendix A presents background information on individual technologies and Appendix B presents the complete results of the economic analyses.

1.5 REFERENCES

1-1 Scientific Design Company, Polygeneration Feasibility Study, prepared for NASA, NAS-10-10-642, November 1983.

TABLE 1-2. CONCEPTS SELECTED FOR STUDY

Resources

- Oil
- Natural Gas
- Coal
- Wind
- Water
- Solar

Technologies for Conversion, Generation, or Production

- External Combustion (Boilers)
- Steam Turbines
- Gas Turbines
- Combined Cycle Turbines
- Internal Combustion (Diesel engine)
- Gasification
- Partial Oxidation
- Steam Reforming
- Liquefaction (H_2)
- Electrolysis
- Air Separation
- Solar Central Receivers
- Solar Photovoltaics
- Wind Turbines
- Fuel Cell
- Cogeneration
- Polygeneration

Technologies for Storage

- Pumped Hydro
- Conventional Cryogenics
- Other Conventional Fuel

TABLE 1-3. CONCEPTS EXCLUDED FROM STUDY

Concept	Reasons for Exclusion From Study[1]			
	Development Status	Resource Availability	Environmental Concerns	Economics
Resources				
● Geothermal		✓		
● Wood		✓		✓[2]
● Refuse		✓		✓[3]
● Agricultural Wastes		✓		✓[2]
● Oil Shale	✓	✓	✓	✓
● Refinery Products		✓		✓
● Spent Solvents		✓		
● Ocean	✓			✓
● Tar Sands	✓	✓	✓	✓
● Nuclear	✓		✓	✓
Technologies for Conversion, Generation, and Production				
● Internal Combustion (Stirling engine)	✓			
● Liquefaction (coal)			✓	✓
● Hydroelectric		✓		
● Binary Cycle Turbines	✓	✓		
● Ocean Thermal	✓			
● Ocean Wave, Tidal Current	✓			
● Magnetohydrodynamics	✓			✓
● Nuclear Fission			✓	✓
● Nuclear Fusion	✓		✓	✓

(continued)

TABLE 1-3. (continued)

Concept	Reasons for Exclusion from Study[1] Development Status	Resource Availability	Environmental Concerns	Economics
Technologies for Storage				
• Compressed Air	✓			✓
• Metal Hydrides	✓			✓
• Flywheel	✓			✓
• Battery				✓
• Magnetic	✓			✓
• Phase Change	✓			✓

---

[1] A "✓" indicates that concerns in that area were sufficient to warrant exclusion of concept from this study. Concerns in each area were the following:

Development Status - relatively undeveloped, major development issues need to be resolved.
Resource Availability - adequate reliable supplies are probably unavailable, resources are not available in quantity at VAFB.
Environmental Concerns - major problems are unresolved, major permitting problems are likely.
Economics - poor due to small scale and state of development.

[2] Generally economic only if resource is readily available on site at no cost, or if steam generation only is featured; generally uneconomic for power generation due to small scale and low steam quality.

[3] Generally economic only if landfill disposal of wastes is very costly (due to transportation distances or limited landfill availability); generally uneconomic for power generation due to small scale and low steam quality.

TABLE 1-4. ELECTRICITY PRODUCTION SYSTEMS SELECTED FOR STUDY

Production Technology	Fuel	Critical Launch Demands (CLD) Only	CLD and Continuous Loads	Continuous Loads Only
Boiler/Steam Turbine (Rankine cycle)	● Natural Gas		✓	✓
	● No. 2 Fuel Oil		✓	✓
	● No. 6 Fuel Oil		✓	✓
	● Coal			
	- AFBC[1]		✓	✓
	- Stoker or PC[2]		✓	✓
Gas Turbine (Brayton cycle)	● Natural Gas	✓	✓	✓
	● No. 2 Fuel Oil[3]	✓	✓	✓
Combined Cycle Turbines	● Natural Gas		✓	✓
	● No. 2 Fuel Oil		✓	✓
	● Fuel Gas			
	- via coal gasification		✓	✓
	- via partial oxidation of No. 6 fuel oil[4]		✓	✓
Diesel Engine (Otto cycle)	● No. 2 Fuel Oil	✓	✓	✓
Fuel Cell[5]	● Fuel Gas			
	- via steam reforming of natural gas		✓	✓
	- via partial oxidation of No. 6 fuel oil[4]		✓	✓
	- via coal gasification		✓	✓
Wind Turbines	--			✓
Solar Central Receiver (Power Tower)	--			✓

(continued)

TABLE 1-4. (continued)

Production Technology	Fuel	Critical Launch Demands (CLD) Only	CLD and Continuous Loads	Continuous Loads Only
Solar Photovoltaics	--			✓
Pumped Hydro Storage (PG&E Grid)	● Electricity/Water	✓		

---

[1] Atmospheric Fluid-bed combustion.

[2] For the turbine sizes considered in this study (10 to 20 MW), stoker coal fired boilers are more commonly used than pulverized coal fired boilers. Larger turbines typically use pulverized coal fired boilers.

[3] Use of No. 6 fuel oil may not be feasible in gas turbines due to its high ash and vanadium contents. Use of fuel gases generated from coal or No. 6 oil is impractical due to the inherently low efficiency of simple gas turbines and fuel gas generation. Thus, these systems were not studied.

[4] Partial oxidation of No. 2 fuel oil is less economic than oxidation of No. 6 fuel oil due to the higher cost of No. 2 fuel oil; thus, No. 2 fuel oil systems were not studied.

[5] Small steam turbine/generator systems are included to make use of by-product steam.

TABLE 1-5. COMMODITIES PRODUCTION SYSTEMS SELECTED FOR STUDY

Production Technology	Fuel/Feedstock	Products
Steam Reforming[1]	Natural Gas	• Liquid Hydrogen
Partial Oxidation[1]	No. 6 Fuel Oil[2]	• Liquid Hydrogen • Gaseous Nitrogen[3]
Gasification[1]	Coal	• Liquid Hydrogen • Gaseous Nitrogen[3]
Air Separation	Electricity, Air	• Liquid Nitrogen • Liquid Oxygen • Gaseous Nitrogen
Electrolysis	Electricity, Water	• Liquid Hydrogen • Liquid Oxygen
Coal Gasification/ Air Separation[4]	Coal	• Liquid Hydrogen • Gaseous Nitrogen • Liquid Nitrogen • Liquid Oxygen

[1] These are principal production technologies; ancillary but required technologies include hydrogen liquefaction, and steam turbines. The steam turbines are used to generate a portion of the plant power requirements from by-product steam.

[2] Partial oxidation of No. 2 fuel oil is less economic than oxidation of No. 6 fuel oil due to the higher cost of No. 2 fuel oil; thus, No. 2 fuel oil systems were not studied.

[3] Coal gasification and partial oxidation plants normally use air separation to produce gaseous oxygen which is used in gasification or oxidation. The remaining separated gaseous nitrogen is then available for blanketing and other uses.

[4] Coal gasification plants normally use air separation to produce gaseous oxygen which is used in gasification. The remaining separated nitrogen is then available for blanketing and other uses. In this system concept, the air separation unit is oversized and redesigned to produce the additional required quantities of liquid nitrogen and liquid oxygen.

TABLE 1-6. COMMODITIES AND ELECTRICITY PRODUCTION SYSTEMS SELECTED FOR STUDY

Production Technologies	Products
Wind Turbines/Electrolysis	● Electricity ● Liquid Hydrogen ● Liquid Oxygen
Wind Turbines/Air Separation	● Electricity ● Liquid Nitrogen ● Liquid Oxygen ● Gaseous Nitrogen
Coal Gasification/Combined Cycle Turbine[1]	● Electricity ● Liquid Hydrogen ● Gaseous Nitrogen

[1] Conceptually similar to NASA's KSC polygeneration concept.

Section 2

CONCLUSIONS AND RECOMMENDATIONS

2.1 CONCLUSIONS

The major conclusions of this feasibility study are presented in Section 2.1.1. Other conclusions and findings are presented in Section 2.1.2.

2.1.1 Major Conclusions

The major conclusions of this study are the following:

- Continuous electricity production
    - Except as noted below, VAFB cannot produce its own electricity at a price competitive with purchase from electric utilities. Fossil fuel based systems for producing electricity are not economically viable due to their relatively small size and consequently their low conversion efficiencies. Most non-fuel based systems, such as solar photovoltaics, are not economically viable because of their high capital cost and relatively low operating factor. The economic viability of electricity production at VAFB is also adversely affected by the relatively low value of electricity and the relatively high cost of fuels at VAFB.
    - Electric power from small wind turbines located on well-exposed ridgecrests in southern VAFB appears to be economically feasible. Additional study is required to verify the available wind resource at VAFB, to provide a more detailed design and cost analysis, and to determine the long-term reliability, operability, and performance characteristics of a wind turbine system.

- Critical launch demand power

  - Pumped hydro storage systems are the lowest cost options for supplying critical launch demand power at SLC-6, unless more than about 24 hours of pumped hydro storage capacity are needed. (Twenty-four hours of storage is about twice the 11-hour duration of critical launch demands.) These storage systems could also be used on a daily basis for VAFB power load management. Gas turbine and diesel systems, the next best systems to meet critical launch demands, will be more costly than pumped hydro systems.

  - Except for the possible use of pumped hydro storage in power load management, none of the systems consisidered to supply critical launch demand power should be considered for continuous service. Continuous service could reduce system reliability, and the high fuel, operating, and maintenance cost make continuous service uneconomic.

- Commodities production

  - Because the USAF currently purchases LH_2 on the West Coast at prices substantially below commercial market prices (~50% discount), there is currently no incentive to produce LH_2 on-site at VAFB. This situation is expected to continue as long as excess LH_2 production capacity exists on the West Coast. If the excess LH_2 production capacity disappears, it is expected that the USAF will have to pay commercial prices for LH_2. If commercial prices were charged to the USAF, on-site production of LH_2 (via the steam reforming of natural gas or the electrolysis of water) does become economically attractive. It is not possible to predict when, if ever, the USAF would begin to pay commercial prices for LH_2.

  - The on-site production of LO_2, LN_2, and GN_2 via air separation is somewhat less expensive than the continued purchase of these commodities.

- Commodities and electricity production

  - NASA/KSC coal gasification/combined cycle polygeneration concept is uneconomic at VAFB because

    - polygeneration capacities are much smaller at VAFB
    - electricity and LH_2 prices (or values for revenues) are much lower at VAFB

        - coal costs are relatively higher at VAFB
        - relatively more electricity (less valuable than LH_2) would be produced at VAFB

    - Novel wind turbine combinations (with electrolysis or air separation) are potentially attractive pending verification of wind resource at VAFB.

2.1.2 Other Conclusions and Findings

Other conclusions and findings of this study are in the areas of: 1) overall system evaluations and rankings, 2) environmental constraints and considerations, and 3) commodity transportation issues.

2.1.2.1 Overall System Evaluations and Rankings - The overall evaluation and ranking summaries are shown in Tables 2-1 through 2-3.

- Despite the differences in basic unit reliabilities which are shown in Tables 2-1 through 2-3, by adding spare units all systems except wind turbines and solar systems can be designed to meet the launch-on-time reliability constraint.

- Except for the steam reforming of natural gas to produce LH_2, all fossil fuel based systems have negative ratings in at least two of the four major areas of evaluation (which are technical, economic, environmental, and reliability). The most common negative ratings for fossil fuel based systems are in the economic and environmental areas. Systems featuring the gasification of coal have negative ratings in all four areas of evaluation.

- All non-fuel systems (wind turbines, solar photovoltaics, solar central receivers, pumped hydro storage, air separation, electrolysis, and combinations of wind turbines with air separation or electrolysis) have positive or neutral ratings in at least three of the four areas of evaluation. Air separation systems have positive ratings in all four areas. Under current trends, steam reforming and electrolysis to produce LH_2 are negatively rated in the economic area. But if the USAF had to pay commercial prices for LH_2, steam reforming and electrolysis would be positively rated in the economic areas as well. Solar photovoltaic systems have a negative rating in the economic area; the negative rating is based on current best estimates of costs for mature solar photovoltaic systems in 1992. Since much on-going research is aimed at reducing the cost of photovoltaic cells and systems, it is possible that the economic rating could eventually change to a positive rating.

TABLE 2-1. OVERALL SYSTEM RATINGS

System	Areas of Evaluation			
	Technical[1]	Economic[2]	Environmental[3]	Reliability[4]
ELECTRICITY PRODUCTION				
Boiler/Steam Turbine				
Natural gas	+	--	--	0
No. 2 fuel oil	+	--	--	0
No. 6 fuel oil	+	--	--	0
Stoker coal	+	--	--	0
AFBC coal	+	--	--	0
Gas Turbine				
Natural gas	+	--	--	0
No. 2 fuel oil	+	--	--	0
Combined Cycle Turbine				
Natural gas	+	--	--	0
No. 2 fuel oil	+	--	--	0
No. 6 fuel oil (via partial oxidation)	0	--	--	--
Coal (via gasification)	--	--	--	--
Diesels	+	--	--	+
Fuel Cells				
Natural gas (via steam reforming)	--	--	+	0
No. 6 fuel oil (via partial oxidation	--	--	--	--
Coal (via gasification)	--	--	--	--
Wind Turbines	+	+	+	0

(continued)

TABLE 2-1. (continued)

System	Areas of Evaluation			
	Technical[1]	Economic[2]	Environmental[3]	Reliability[4]
Solar Central Receiver	0	--	+	+
Solar Photovoltaics	+	--	+	+
Pumped Hydro	+		+	+
COMMODITIES PRODUCTION				
Steam Reforming	+	-/+[5]	+	+
Oil Partial Oxidation	+	--	--	0
Coal Gasification	--	--	--	--
Air Separation	+	+	+	+
Electrolysis	+	-/+[5]	+	+
Coal Gasification/Air Separation	--	--	--	--
COMMODITIES AND ELECTRICITY PRODUCTION				
Wind Turbines/Electrolysis	0	+	+	0/+[6]
Wind Turbines/Air Separation	0	+	+	0/+[6]
Coal Gasification/Combined Cycle Turbine	--	--	--	--

---

[1] "+" denotes well developed, widely applied systems in all areas; "0" denotes systems whose components are well developed but commercial applications are few or do not exist; "--" denotes systems with one or more components still in demonstration.

[2] "+" denotes positive net present value (NPV); "--" denotes negative NPV.

[3] "+" denotes inherently clean system or system with minor emissions; "--" denotes system which generates hazardous wastes and/or requires air emission offsets.

[4] "+" denotes high single-unit reliability (∿95%); "0" denotes moderate single-unit reliability (∿90%); "--" denotes low single-unit reliability (∿85%).

[5] "-/+": "--" under government LH_2 price trends, "+" under commercial LH_2 price trends.

[6] 0/+: "0" for wind turbines, "+" for electrolysis or air separation.

TABLE 2-2. MOST ATTRACTIVE SYSTEMS FOR CONTINUOUS PRODUCTION OF ELECTRICITY AND/OR COMMODITIES[1]

System	Areas of Evaluation			
	Technical[2]	Economic[3]	Environmental[4]	Reliability[5]
ELECTRICITY PRODUCTION				
Wind Turbines	+	+	+	0
Solar Photovoltaics	+	--	+	+
COMMODITIES PRODUCTION				
Steam Reforming	+	-/+[6]	+	+
Air Separation	+	+	+	+
Electrolysis	+	-/+[6]	+	+
COMMODITIES AND ELECTRICITY PRODUCTION				
Wind Turbines/Electrolysis	0	+	+	0/+[7]
Wind Turbines/Air Separation	0	+	+	0/+[7]

---

[1] Systems shown here are those systems from Table 2-1 which have at most only one negative or zero rating in the four areas of evaluation.

[2] "+" denotes well developed, widely applied systems in all areas; "0" denotes systems whose components are well developed but commercial applications are few or do not exist.

[3] "+" denotes positive net present value (NPV); "--" denotes negative NPV.

[4] "+" denotes inherently clean system or system with minor emissions.

[5] "+" denotes high single-unit reliability (∿95%); "0" denotes moderate single-unit reliability (∿90%).

[6] "-" under government LH_2 price trends, "+" under commercial LH_2 price trends.

[7] 0/+" "0" for wind turbines, "+" for electrolysis or air separation.

TABLE 2-3. MOST ATTRACTIVE SYSTEMS FOR SUPPLYING CRITICAL LAUNCH POWER DEMAND

System	Areas of Evaluation[1]			
	Technical[2]	Economic[3]	Environmental[4]	Reliability[5]
Gas Turbine				
Natural Gas	+	0	--	0
No. 2 fuel oil	+	0	--	0
Diesel Engines	+	0	--	+
Pumped Hydro	+	+	+	0

[1] Systems shown here have lower capital costs than alternative systems such as gas-fired boiler/turbines. Positive ratings obviously indicate positive factors while zero ratings indicate neutral factors and negative ratings indicate negative factors.

[2] "+" denotes well developed, widely applied systems in all areas.

[3] For systems supplying critical launch power demands only, the most important economic parameter is the total capital investment; because of their short hours of operation, operational costs are of lesser importance. The relative ranking of these systems varies with the set of design bases. The gas turbine systems would be the least expensive of the four options if: 1) pumped hydro alternatives were required to have capacities greater than 24 to 36 hours, and 2) diesel engine alternatives required multiple units to achieve the 95% reliability criterion. Based on a preliminary analysis, new diesel engines may be more reliable than gas turbines and thus could meet the 95% reliability criterion with single units. But if multiple diesel units were required, equivalent gas turbine systems would be less expensive.

[4] "+" denotes inherently clean system or system with minor emissions. "--" denotes system which generates hazardous wastes and/or requires air emission offsets.

[5] "+" denotes high single-unit reliability (∿95%). "0" denotes moderate single-unit reliability (∿90%).

2.1.2.2 Environmental Constraints and Considerations

- All of the energy and commodity production systems must be designed to meet applicable California environmental regulations. However, even with stringent best available air emission controls, air emission offsets will be needed for NO_x for most systems which combust fossil fuels. The availability of these offsets, either inside or outside VAFB, may be limited, but they could not be definitely specified in this study. Costs of obtaining these offsets may be high but have not been determined.

- Some of the fossil fuel conversion systems would produce potentially hazardous wastes and these would need to be contained and shipped offsite for treatment and disposal.

2.1.2.3 Commodity Transportation Issues

- Rail transportation is cheaper and safer than truck transportation.

- Public health and safety concerns over transportation of cryogenics could provide an incentive for on-site production of commodities.

2.2 RECOMMENDATIONS

The major project recommendations are in the areas of: 1) continuous electricity production, 2) critical launch demand power, 3) commodities production, and 4) commodities and electricity production.

- Continuous electricity production
  - Perform more detailed evaluation of wind turbine systems. Verify wind resource at locations on well-exposed ridgecrests in southern VAFB. Perform more detailed design and economic analysis. Purchase test wind turbines of ~200 kW (possible cost sharing with vendor) and perform testing to determine reliability, operability, and performance characteristics. Investigate potential for interferences with communications. Investigate combination with pumped hydro storage to meet critical launch demands and to smooth out production variations.

- Continue to rely on power purchased from the electric utility grid.

- Monitor future developments in solar photovoltaics, particularly with respect to capital investment costs.

- Perform additional preliminary cost estimates for coal systems larger than 50 MW; these systems have overall conversion efficiencies much greater than the small systems considered in this study. Excess power can be exported to the utility grid.

- Critical launch demand power

  - Perform more detailed evaluation of pumped hydro storage with respect to site-specific construction design features at VAFB. Perform more detailed design and economic analysis. Define power duration requirements (12 hours vs. 24 hours or more). Perform more detailed comparative analysis of pumped hydro, diesel, and gas turbines. Also, further examine existing and alternate grid power supply reliability data for mean time between failures and mean time of repair.

- Commodities production

  - Continue to purchase liquid hydrogen from West Coast vendors.

  - Perform more detailed design and cost studies of air separation with end result of possible system installation.

  - Monitor future trends in commercial and government LH_2 prices to anticipate escalation of LH_2 prices to commercial price levels.

- Commodities and electricity production

  - After more detailed investigation of wind turbine systems (as discussed above), perform detailed analysis of wind turbine systems in combination with electrolysis or air separation.

Section 3

ENERGY AND COMMODITY REQUIREMENTS

A variety of energy and commodity resources are needed to support current VAFB operations and future space shuttle operations at VAFB/SLC-6. The resources which are considered in this study are electrical power, liquid hydrogen, liquid oxygen, and gaseous and liquid nitrogen. The VAFB/SLC-6 requirements for these resources are identified in this section, and used in later sections to determine the characteristics of systems which could be built at VAFB to supply these resources. Several other energy and utility resources used at VAFB are also identified and discussed in this section. However, because of their relatively lesser importance, the on-site production of these resources (or their substitutes) is not considered in this study. The resources in this group - natural gas, diesel oil, propane, and water - are also used as feedstocks in the production of the principal resources considered in this study. Several other resources used at VAFB, including jet fuels and various rocket propellants, are outside the scope of this study.

Section 3.1 discusses the requirements at VAFB for energy and utility resources: electrical power, natural gas, diesel oil, propane, water, and (briefly) process heating and cooling. Section 3.2 discusses the requirements at VAFB for commodity resources, including liquid hydrogen, liquid oxygen, and gaseous and liquid nitrogen.

3.1 ENERGY AND UTILITY RESOURCES

Each of the energy and utility resources is discussed separately below.

3.1.1 Electrical Power

Both economic and reliability factors are of major importance in the supply of electrical power to VAFB. In fact, as discussed in Section 1.0, the need for a reliable backup power source to support space shuttle launches at SLC-6 was one of the major drivers for this study's initiation.

The current electrical power system at VAFB is the dual loop supply system shown in Figure 3-1. The dual loop is a recent step taken to improve electrical reliability at VAFB/SLC-6. Pacific Gas and Electric (PG&E) supplies electricity to this loop through separate substations, providing an overall reliability of about 99.998 percent. This current grid reliability may decrease in the future if the utility power reserve margins decrease. VAFB currently is exempt from power curtailments during brown-outs; however, VAFB can lose all power during PG&E system blackouts.

To support the on-time launch of space shuttles, the USAF has determined that support systems must have reliabilities of 99.9999 percent. The current electrical power supply from PG&E, with its reliability of 99.998 percent, is obviously unable to meet the stringent reliability constraint of the launch-on-time requirement. Back-up power systems are thus needed to increase the overall power system reliability to 99.9999 percent. Based on an analysis of the overall system reliability requirement and the existing grid reliability, the backup power supply would need to have a reliability of 95 percent to meet the launch-on-time reliability constraint. If the existing PG&E grid reliability decreased to 99.995 percent, a backup power reliability of 98 percent could be needed to meet the launch-on-time reliability constraint of 99.9999 percent. The critical launch operations have a duration of 11 hours (T-8 to T+3); it is during this period that the overall electrical supply system must have a reliability of 99.9999 percent to meet the launch-on-time reliability constraint.

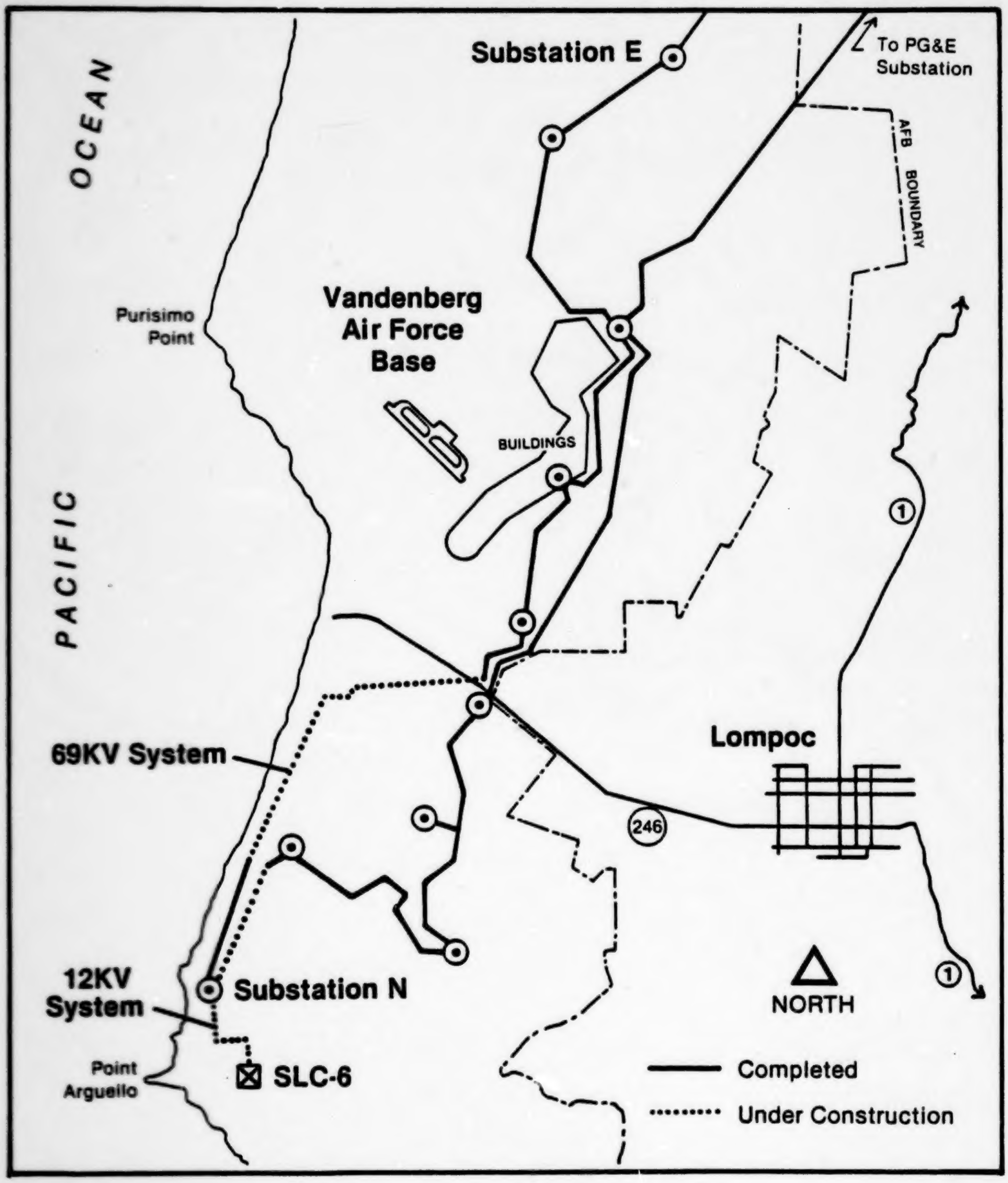

PACIFIC OCEAN
Substation E
To PG&E Substation
AFB BOUNDARY
Purisimo Point
Vandenberg Air Force Base
BUILDINGS
①
69KV System
Lompoc
246
12KV System
Substation N
NORTH
①
Point Arguello
SLC-6
Completed
Under Construction

Figure 3-1. VAFB dual loop electrical supply system

During shuttle launch operations, the coincident peak load for critical operations at SLC-6 is about 9.1 MW (3-1). A small backup power system currently employed at VAFB can supply only a portion of the power needed to launch the shuttle.

Current and estimated future demands for electrical power at VAFB are shown in Figure 3-2 (3-2). Current peak demands are about 25 MW while the baseload demand is about 15 MW. Future demands include the expected demands of space shuttle operations; future peak demands are estimated to be 35-42 MW while future baseload demands are estimated to be 21-25 MW. Recent monthly demand and consumption profiles are shown in Figure 3-3. While the peak demand averaged over 7 months is just under 25 MW, the average power consumption is only about 17 MW (12.3 million kWh per month).

In this study, electrical power requirements of 9 to 20 MW were considered. Nine MW corresponds to the minimum capacity backup power system capable of meeting the launch-on-time reliability constraint. Larger capacities would be installed when multiple unit installations were required to meet the launch-on-time reliability constraint. Twenty MW is the largest system capable of generating electrical power for on-site VAFB uses only; larger systems would either operate at reduced capacity factors (that is, operate at levels below their capacity rating) or would produce excess power for sale to the utility grid. The larger systems are more economically viable than smaller systems when both are operated at capacity due to economies of scale and the higher conversion efficiencies of larger systems. However, systems larger than 20 MW were not considered in this study because of the focus on supplying reliable power for shuttle launch demands and baseload VAFB demands only. The economic viability of slightly larger systems at VAFB, unless equivalent to the large-sized (100 MW+) systems used by electrical utilities, is probably about the same as the systems considered in this study.

3.1.2 Natural Gas

Southern Pacific Gas is the current supplier of natural gas for VAFB. The natural gas is used mainly for space heating and other domestic uses. As

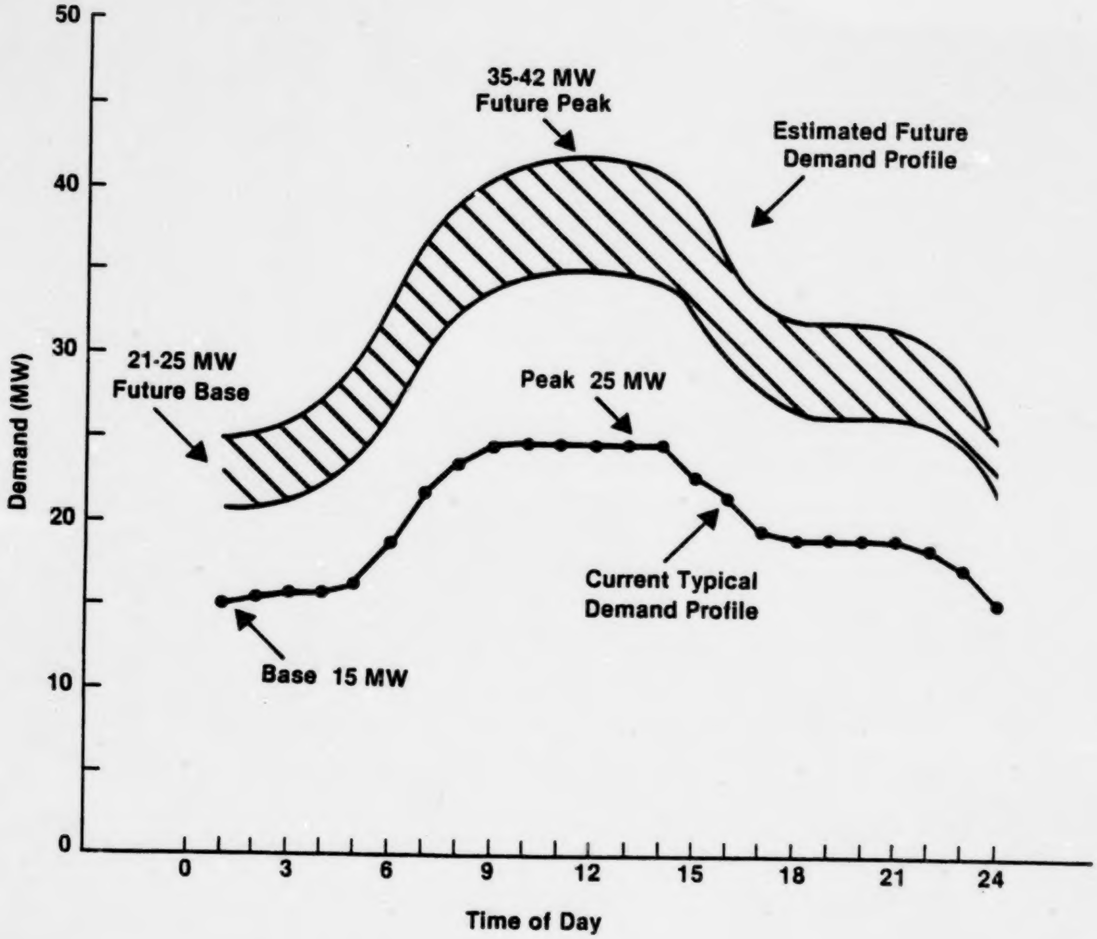


Figure 3-2. VAFB electric demand profile

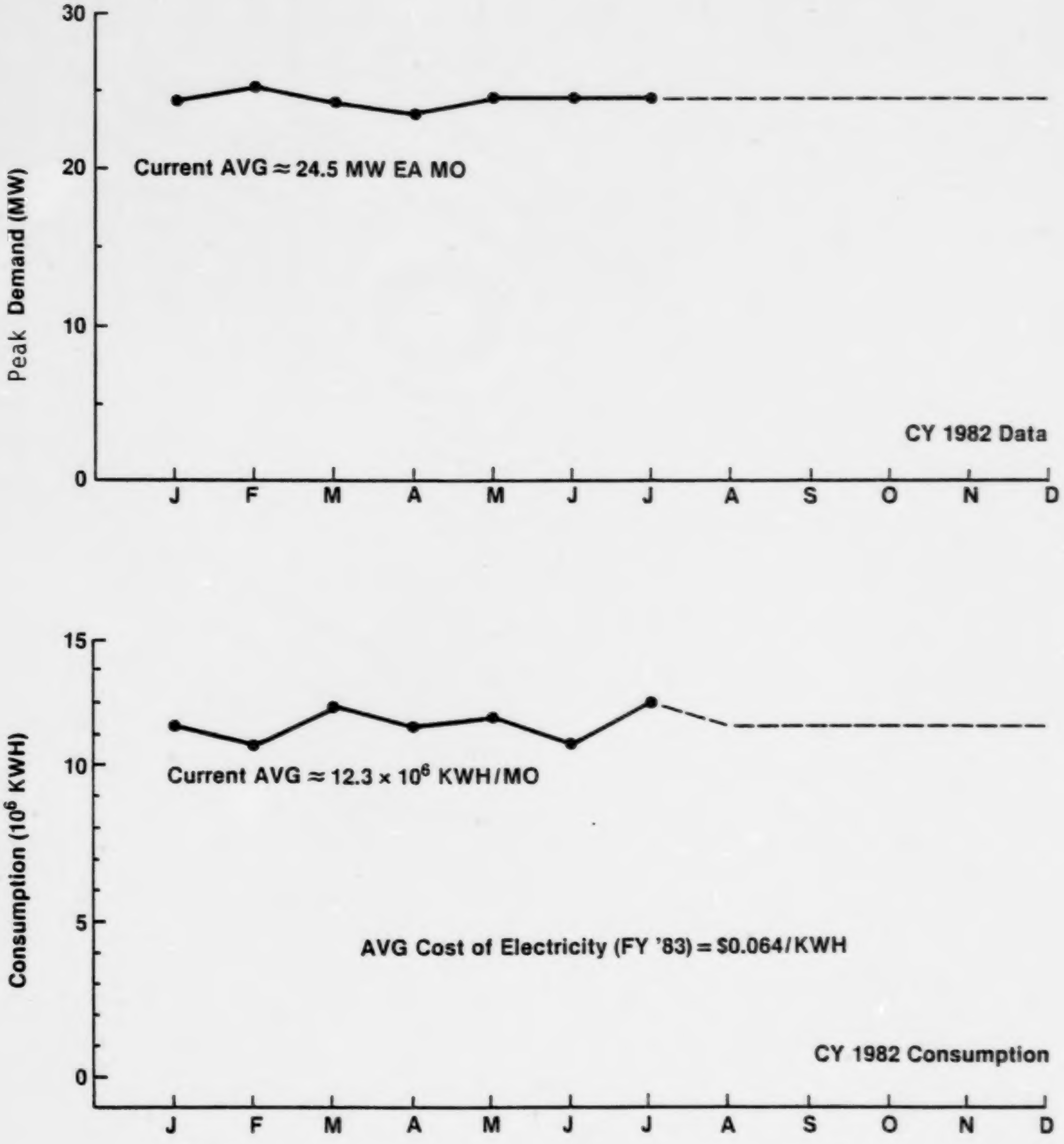


Figure 3-3. VAFB monthly electric demand and consumption profile

shown in Figure 3-4, the monthly consumption of natural gas varies with seasonal space heating needs. In 1983 the total consumption of natural gas at VAFB was about 605,000,000 cubic feet. Excluding the possible requirements for the new facilities considered in this report, natural gas use at VAFB is not expected to increase.

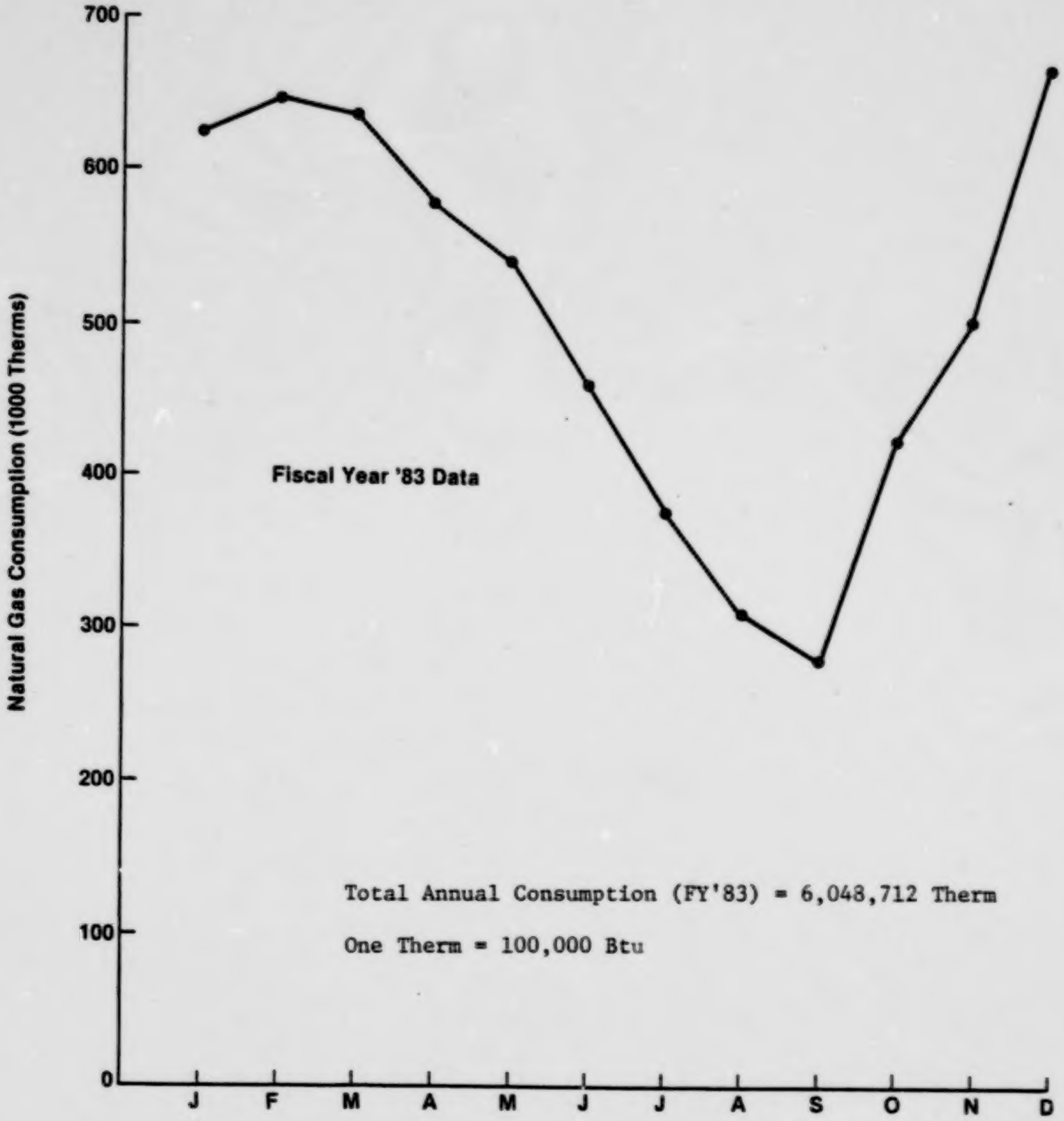
The current gas service is low pressure for light industrial, commercial, and residential uses. The nearest high pressure (~200 psi) trunk line capable of serving large industrial loads is in Lompoc. Natural gas service at VAFB currently does not extend to SLC-6.

Southern Pacific Gas has 5 curtailment classes, with Class 1 being the highest priority and Class 5 the lowest priority. VAFB is a multiple-priority customer. Approximately 52 percent of VAFB service is Priority 1 and the remaining 48 percent is Priority 2. Since both of these classifications are high priorities, it is not expected that VAFB will suffer natural gas curtailment.

3.1.3 Diesel Oil, Propane, Water, and Heating/Cooling

VAFB requirements for diesel oil, propane, and water are shown in Table 3-1. Excluding the possible requirements for the new facilities considered in this report, use of diesel oil and propane is not expected to increase. Baseline water use is expected to increase from the existing yearly consumption of 1.5 billion gallons to 1.8 billion gallons by the year 2000. Although currently supplied by wells on base, future water supplies for VAFB will also include state aqueduct water (3-2).

There are no significant process heating and cooling loads at VAFB nor any centralized steam or heat distribution system (3-2). Thus neither the heat loads nor the distribution systems exist which could use waste heat from on-base plants. Heating and cooling loads are thus not considered further in this project. (If on-base power production or commodity production were viable, the use of their waste heat may deserve future consideration. The use of this waste heat is usually termed cogeneration.)



Fiscal Year '83 Data

Total Annual Consumption (FY'83) = 6,048,712 Therm

One Therm = 100,000 Btu

Figure 3-4. VAFB monthly natural gas consumption profile

TABLE 3-1. ADDITIONAL VAFB UTILITY REQUIREMENTS[1]

Utility	Annual Consumption
Diesel oil	1,400,000 gallons
Propane	100,000 gallons
Water	1,500,000,000 gallons[2]

[1] Based on data for 1983. Requirements for future years are either expected to be the same or are unknown (except as noted in footnote 2).

[2] Water requirements are projected by VAFB Civil Engineering to increase to 1,800,000,000 gallons by 2000.

3.2 COMMODITY RESOURCES

The anticipated consumption of liquid hydrogen, oxygen, and nitrogen commodities is based solely on requirements to support shuttle operations at SLC-6: possible uses of these commodities for other non-shuttle operations are not considered in this study. However, gaseous nitrogen is widely used at VAFB for purging and blanketing and its general use is considered in this study. (Currently, VAFB generates gaseous nitrogen by vaporizing liquid nitrogen.)

The yearly consumption of liquid commodities as a function of the shuttle launch rate is estimated in Figure 3-5. The average commodities' consumptions per launch are the following:

liquid hydrogen	134 tons/launch
liquid oxygen	1060 tons/launch
liquid nitrogen	640 tons/launch

These data were obtained from USAF program requirements, and are based on experience at the Kennedy Space Center.

In addition to the liquid commodities, an additional 37 tons (690 scfm @ 150 psig) of gaseous nitrogen are required daily at VAFB for purging and blanketing. For those production technologies that produce liquid or gaseous oxygen as a final product or as a feedstock, gaseous nitrogen can be produced at a marginal cost.

On-site plants designed to produce the various commodities must be designed to produce more than the average launch requirements above because: 1) plant production must compensate for periods when the plant is inoperable due to planned and unplanned outages, 2) plant production must be based on supplying the launch requirements with less time between launches than the average expected under the actual shuttle launch rate, and 3) plant production must compensate for commodity losses during transfer and storage. In addition, a plant design safety factor of 10 percent has been incorporated.

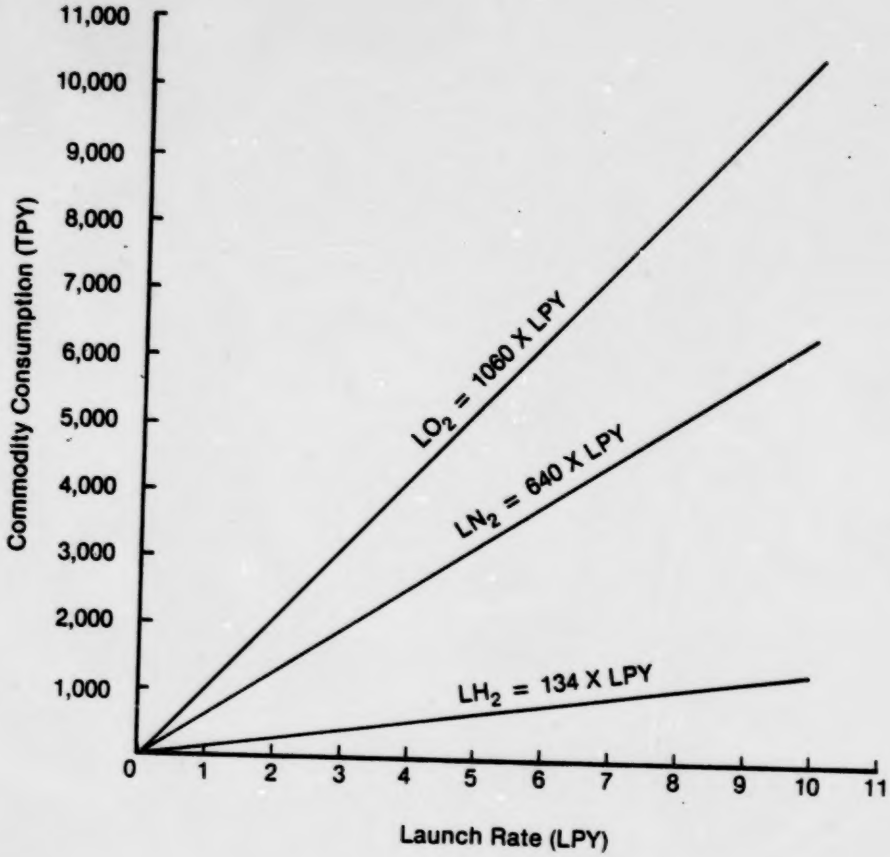


Figure 3-5. SLC-6 commodity consumption

The resulting commodity plant design capacities are shown in Figure 3-6. The design capacities presume that the maximum system capacities are 33 percent greater than the nominal launch rate; that 33 percent factor is based on planning at the Kennedy Space Center which provides for a nominal launch rate of 18 launches per year and a design capacity of 24 launches per year.

Based on Figure 3-6, a nominal launch rate at VAFB of 10 launches per year would require plants capable of producing 47.1 TPD of liquid oxygen, 28.4 TPD of liquid nitrogen, and 5.95 to 7.02 TPD of liquid hydrogen, depending on the hydrogen plant reliability.

3.3 REFERENCES

3-1 Interoffice correspondence from W. A. Kammer to R. Schult (The Aerospace Corporation), 22 December 1983, Information of Power Requirements for STS at SLC-6.

3-2 USAF communication or documents.

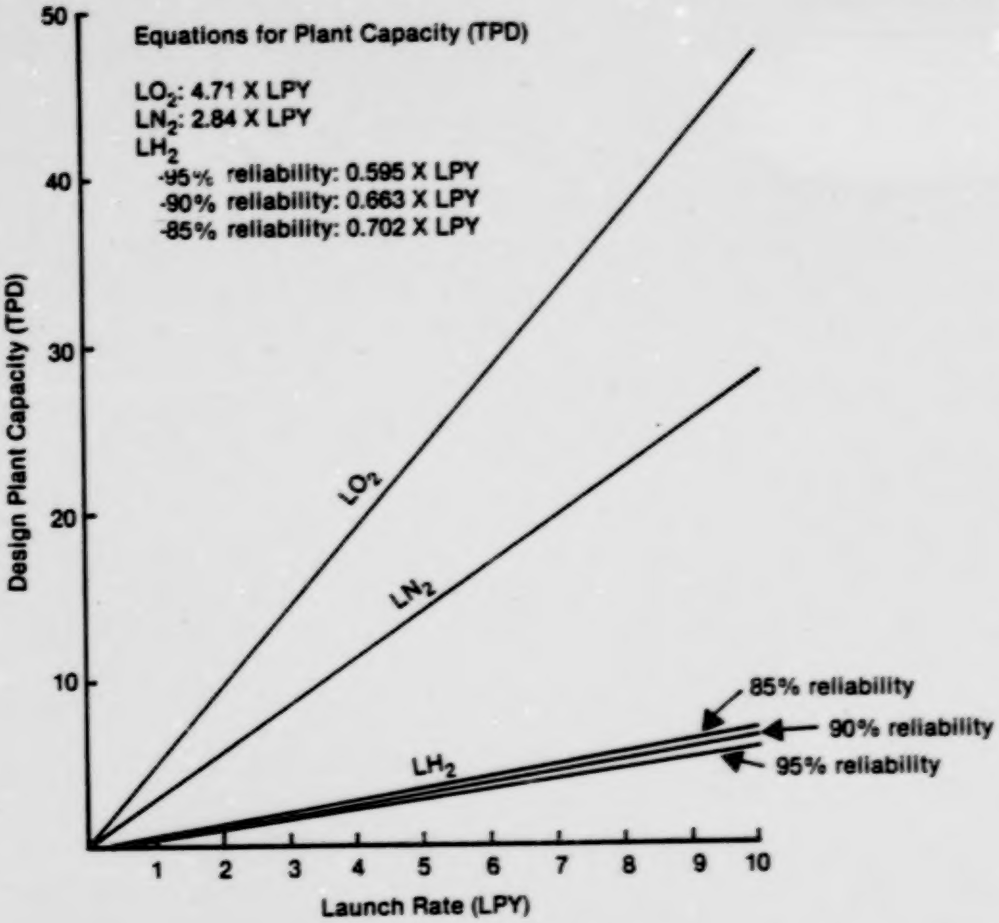


Figure 3-6. Required commodity plant design capacities

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Section 4

ENVIRONMENTAL CONSTRAINTS AND CONSIDERATIONS

Any systems constructed to produce electricity and/or commodities at VAFB must comply with all applicable air quality, water quality, and solid waste regulations. These environmental constraints could preclude the use of some technologies if emissions could not be practically controlled to the regulated levels. Alternately, the environmental constraints could require use of emission controls whose expense would preclude the use of certain production technologies.

Before building or operating any new production technology, various environmental permits must be received from federal, state, and local regulatory authorities. These permits constitute formal reviews of the new system's emissions and emission controls. The preparation of the required permit applications and supporting materials not only can be expensive but also add to the length of time needed to plan and complete new construction.

Both permitting requirements and specific emission regulations and considerations are addressed in this chapter. Section 4.1 discusses the general permitting requirements for the energy/commodity technology options considered in this study. Section 4.2 presents air quality considerations including the air pollutant attainment status at VAFB, applicable air pollution regulations, and potential air pollution control technologies that might be required for the energy/commodity options. Sections 4.3 and 4.4 discuss current operations at VAFB and regulatory requirements for water/wastewater quality and solids waste management. General conclusions pertaining to environmental considerations for the energy/commodity technology options are presented in Section 4.5.

4.1 GENERAL PERMITTING REQUIREMENTS

Table 4-1 summarizes the regulatory agencies expected to have primary involvement with permitting the various energy/commodity technology options. As shown, the regulatory agencies expected to be most involved in an eventual VAFB energy/commodity project are the Santa Barbara County Air Pollution Control District (SBCAPCD) and the California Regional Water Quality Control Board - Central Coast Region (CRWQCB). Permits required by these agencies are listed in Table 4-2.

Energy/commodity technologies that emit air contaminants are required to obtain an Authority to Construct and a Permit to Operate from the SBCAPCD. The CRWQCB issues National Pollutant Discharge Elimination System (NPDES) permits for wastewater discharges to surface waters (e.g., discharge to an evaporation/percolation pond). Therefore, the type of permit from the CRWQCB will depend on the method of waste treatment and disposal.

Any energy/commodity technology involving the construction of dams and reservoirs may require a Certificate of Approval from the California Department of Water Resources, Division of Safety of Dams. Several technologies may not require permits from any environmental regulatory agencies. These include hydrogen liquefaction, electrolysis, air separation, solar photovoltaics, wind turbines, and hydrogen storage.

One other type of permit that could potentially apply to VAFB energy/commodity facilities is a hazardous waste management permit from the California Department of Health Services (DHS) and/or the Environmental Protection Agency (EPA). Currently, DHS has proposed regulations that, if approved, could result in full hazardous waste management permitting authority for California. However, at this time, both EPA and DHS handle hazardous

TABLE 4-1. REGULATORY AGENCIES WITH PROBABLE PERMIT AUTHORITY

Technology Option	Regulatory Agencies[1]
External Combustion (Boilers)/Steam Turbines	SBCAPCD, CRWQCB
Gas Turbines	SBCAPCD, CRWQCB
Combined Cycle Turbines	SBCAPCD, CRWQCB
Internal Combustion Engines	SBCAPCD
Coal Gasification	SBCAPCD, CRWQCB
Partial Oxidation	SBCAPCD, CRWQCB
Steam Reforming	SBCAPCD, CRWQCB
H_2 Liquefaction	Probably no involved agencies
Electrolysis	Probably no involved agencies
Air Separation	Probably no involved agencies
Solar Central Receiver (Power Tower)	SBCAPCD, CRWQCB
Solar Photovoltaics	Probably no involved agencies
Wind Turbines	Probably no involved agencies
Fuel Cells	SBCAPCD, CRWQCB
Commodities and Electricity Production	SBCAPCD, CRWQCB
Pumped Hydro	California Department of Water Resources
Hydrogen Storage	Probably no involved agencies

[1] SBCAPCD - Santa Barbara County Air Pollution Control District
CRWQCB - California Regional Water Quality Control Board - Central Coast Region

TABLE 4-2. PERMIT REQUIREMENTS FOR INVOLVED REGULATORY AGENCIES

Regulatory Agency	Permit
Santa Barbara County Air Pollution Control District (SBCAPCD)	• Authority to Construct - required prior to commencing construction. • Permit to Operate - granted once constructed project shows compliance with permit conditions and regulations.
California Regional Water Quality Control Board - Central Coast Region (CRWQCB)	• National Pollutant Discharge Elimination System (NPDES) permit - required for discharges to surface waters. • Waste Discharge Requirements (WDR) - required for discharges that may affect groundwater quality.
California Department of Water Resources, Division of Safety of Dams	• Certificate of Approval - required for reservoirs with a storage capacity of 50 acre-feet or more.

waste facility permits in California. If VAFB has energy/commodity facilities that generate hazardous wastes, VAFB will need to treat, store, and/or dispose of these wastes on base or have the wastes transported off base for treatment and/or disposal. Treatment, storage, or disposal of hazardous wastes on base may require a hazardous waste facility permit from the DHS and/or the EPA.

Current air pollution control regulations could require an energy/commodity project to obtain a permit from the EPA as well as the SBCAPCD. The EPA currently administers the Prevention of Significant Deterioration (PSD) program for emissions of attainment pollutants in Santa Barbara County. However, proposed revisions to the SBCAPCD regulations will establish New Source Review (NSR) requirements for emissions of nonattainment pollutants and PSD requirements for emissions of attainment pollutants. With the inclusion of PSD requirements in the SBCAPCD regulations, new and modified sources in the County will no longer need to obtain a separate PSD permit from the EPA. The proposed revisions appear to be certain; consequently, it is assumed that new VAFB energy/commodity facilities will be reviewed under the proposed regulations.

Anticipated energy/commodity facilities appear to be exempt from certain California permitting and regulatory requirements due to VAFB's status as a federal and military facility. The California Environmental Quality Act (CEQA) requires projects that will have significant environmental impact to file an environmental impact report (EIR). CEQA sets up an environmental review of proposed projects with the delegation of a "lead" agency to spearhead the review. This lead agency is responsible for the preparation of an environmental document such as an EIR or a negative declaration. However, contacts with the California Governor's Office, Office of Planning and Research, indicated that the provisions of CEQA do not apply to federal military facilities. Consequently, eventual energy/commodity facilities at VAFB will not require environmental review under the provisions of CEQA.

Although CEQA will not apply, the National Environmental Policy Act (NEPA) may apply. The President's Council on Environmental Quality (CEQ) regulates NEPA. If the proposed energy/commodity facilities constitute a major federal action, NEPA requires the preparation of an environmental impact statement (EIS). However, it should be noted that an EIS has already been prepared for the overall space shuttle program at VAFB. This EIS was submitted to Air Force Systems Command. The EIS included discussions of power generation facilities to suppport the shuttle program. Therefore, another EIS specifically for the energy/commodity facilities may not be required.

The County of Santa Barbara Resource Management Department issues various land use and building permits and approvals for projects within Santa Barbara County. If CEQA were applicable at VAFB, the Resource Management Department would probably be the "lead" agency in reviewing the environmental impact of energy/commodity facilities. However, contacts with the Resource Management Department indicate that they have no review or permitting authority for projects at VAFB. Therefore, eventual VAFB energy/commodity facilities will not require review or approval by the County of Santa Barbara Resource Management Department.

The California Coastal Commission (CCC) issues coastal development permits for proposed projects or developments within the coastal region. It has not been determined whether proposed VAFB energy/commodity facilities would be located within the coastal region. Regardless, contacts with CCC indicate that federal military facilities are exempt from coastal development requirements. Therefore, eventual VAFB energy/commodity facilities will apparently not require review or approval by the CCC. The shuttle program EIS states that the CCC reviewed the overall space shuttle program and determined it to be as consistent as practicable with the California Coastal Act.

Energy/commodity facilities at VAFB will also be exempt from the permitting requirements of the California Energy Commision (CEC) and the California Public Utilities Commission (CPUC). Both agencies exempt power generation facilities that generate under 50MW of power. Proposed energy facilities for VAFB will generate approximately 10-20 MW and therefore are exempt from CEC and CPUS requirements.

4.2 AIR QUALITY CONSIDERATIONS

This section presents air quality considerations of proposed energy/commodity facilities at VAFB. These considerations include the air pollutant attainment status of VAFB, applicable air pollution control regulations, and air pollution control technologies.

4.2.1 Air Pollutant Attainment Status

Table 4-3 summarizes the air pollutant attainment status of Santa Barbara County with respect to ambient air quality standards. VAFB is in the northern portion of Santa Barbara County. As shown in Table 4-3, VAFB is in an attainment area for all pollutants. For northern Santa Barbara County, the attainment status for ozone was recently redesignated from nonattainment to attainment. However, the SBCAPCD noted that potential offshore oil development could result in increased ambient ozone concentrations, and the area could again be designated as nonattainment for ozone.

The applicability of the Santa Barbara County APCD regulations depends on the attainment status of the subject pollutants. New Source Review (NSR) requirements apply to emissions of nonattainment pollutants whereas Prevention of Significant Deterioration (PSD) requirements apply to emissions of attainment pollutants. Since VAFB is in an attainment area for all pollutants, proposed energy/commodity facilities will be reviewed under PSD requirements.

4.2.2 Air Pollution Regulations

Currently, both the SBCAPCD and the EPA administer air pollution regulatory programs in Santa Barbara County. The SBCAPCD administers New Source Review (NSR) requirements and the EPA administers Prevention of

TABLE 4-3. SANTA BARBARA COUNTY AIR POLLUTANT ATTAINMENT STATUS

Portion of County	Carbon Monoxide (CO)	Ozone (O_3)	Oxides of Nitrogen (NO_x)	Oxides of Sulfur (SO_x)	Total Suspended Particulate (TSP)
Northern	A	A	A	A	A*
Southern	NA	NA	A	A	A

A - attainment

NA - nonattainment

*The majority of northern Santa Barbara County including VAFB is attainment for TSP. However, the Santa Maria area is nonattainment for TSP.

Significant Deterioration (PSD) requirements. Proposed amendments to the SBCAPCD regulations will change this situation. Proposed amendments to the SBCAPCD regulations will establish NSR requirements for emissions of nonattainment pollutants and PSD requirements for emissions of attainment pollutants. With the inclusion of PSD requirements in the County's regulations, new and modified sources in the County will no longer need to obtain a separate PSD permit from the EPA. That is, all air quality permits will be obtained directly from the SBCAPCD. Contacts with staff of the SBCAPCD indicate that adoption of the proposed amendments in early 1984 is certain. Consequently, it is assumed that new VAFB energy/commodity facilities will be reviewed under the amended SBCAPCD regulations.

In general, the SBCAPCD regulations include requirements for performing air quality impact analyses (AQIA), using Best Available Control Technology (BACT) for air pollution control, and providing emission trade-offs or offsets. These requirements are triggered based on the net emission increases associated with the new or modified source (in this case, the energy/commodity facilities). Table 4-4 summarizes the primary requirements and issues of SBCAPCD regulations. Both current and proposed requirements are presented for comparison. The proposed requirements are generally more stringent than the current requirements.

Given that VAFB is currently in an attainment area for all pollutants, new energy/commodity facilities will be reviewed under SBCAPCD's proposed PSD requirements. Based on the definition of stationary source, the entire VAFB will be considered as one stationary source for this evaluation. That is, all of VAFB's net emissions increases and decreases since July 2, 1979, will be added to the net emissions increases associated with the energy/commodity facilities. The resulting total net emissions increases will then be used to determine the applicability of various requirements (e.g., BACT, AQIA, etc.). Consequently, emissions increases beyond those associated with just the energy/commodity facilities must be considered for rule compliance.

TABLE 4-4. SUMMARY OF SANTA BARBARA COUNTY APCD REGULATIONS

Issue	New Source Review (NSR)		Prevention of Significant Deterioration (PSD)
	Current	Proposed	
Best Available Control Technology (BACT) - Definition	Sources emitting >5 lb/hr but <10 lb/hr - most effective control technique accounting for energy, environmental, and economic impacts. Sources emitting ≥10 lb/hr - most stringent of (1) most effective control achieved in practice for source type (2) other control that is technically feasible and cost-effective for source type (3) most effective emission limitation contained in any federally approved SIP.	More stringent of (1) most effective control device, emission limit, or control technique achieved in practice for source type (2) other control that is technically feasible and cost-effective; BACT never to be less stringent than required by any local, state, or federal regulations.	Same as proposed NSR rule.
Net Emissions Increase - Definition	Sum of stationary source's pollutant increases and decreases for preceding five years; mandated decreases not applicable.	Same as current rule except that baseline data is July 2, 1979.	Same as proposed NSR rule.
Stationary Source - Definition	Structure, building, facility, equipment installation, or operation on one or more bordering properties owned or operated by same legal owner/operator or under joint/concurrent construction or operation; includes cargo carriers associated with source.	Building, structure, or facility expanded to include all activities that belong to the same industrial grouping and under common ownership, etc.; fugitive emissions added to definition; the inclusion of trains as cargo carrier is not defined.	Same as proposed NSR rule with the addition that stationary source is facility-wide for attainment pollutants (i.e., VAFB is considered one stationary source for rule compliance purposes).
Best Available Control Technology (BACT) - Requirement	Sources with net emissions increase ≥5 lb/hr except CO at 100 lb/hr or 1,000 lb/day (pollutant by pollutant basis).	Sources with net emissions increase ≥2.5 lb/hr except CO at 20 lb/hr or 150 lb/day (nonattainment pollutants).	Sources with net emissions increase ≥5 lb/hr except CO at 50 lb/hr or 550 lb/day (attainment pollutants).
Air Quality Impact Analysis (AQIA) - Requirement	Applies to new sources with net emissions increase >10 lb/hr; modified sources with net emissions increase ≥5 lb/hr if total emissions after modifications ≥15 lb/hr.	Applies to new or modified sources with net emissions increase ≥5 lb/hr but <10 lb/hr (nonattainment pollutants) except for CO at 100 ton/yr.	Class I or Class I Impact Area - applies to new or modified sources with net emissions increase >20 lb/hr for CO or >5 lb/hr for other attainment pollutants. Class II Area - applies if total emissions (not just net emissions increase) from new or modified source >20 lb/hr (attainment pollutants).

(continued)

TABLE 4-4. (continued)

Issue	New Source Review (NSR)		Prevention of Significant Deterioration (PSD)
	Current	Proposed	
Emission Trade-Offs - Requirement	Offset entire net emissions increase if ≥25 lb/hr or 230 lb/day; cutoffs less if AQIA demonstrates violation or interference with standard (pollutant by pollutant basis)	Offset entire net emissions increase if ≥10 lb/hr, 240 lb/day, or 25 ton/year (except CO); cutoffs less if AQIA demonstrates violation or interference with standard (nonattainment pollutants).	Class I or Class I Impact Area - offsets not required. Class II Area - offset entire net emissions increase if >10 lb/hr for ROC, NO_x, SO_x, or PM (attainment pollutants).
Location of Emission Trade-Offs and Trade-Off Ratios	Upwind or within 15 miles of new or modified source; ratio of 1.2 to 1.	Same as current rule except trade-off ratio may increase subject to reasonable further progress.	Within 15 mile radius at 1.2 to 1 ratio; trade-offs may be obtained upwind or outside of district or Air Basin subject to limitations; increment consumption may be allowed if insufficient trade-offs available.
Air Monitoring	No specific requirements; State Health and Safety Code, Clean Air Act	Same as current rule.	Required if net emissions increase >5 lb/hr for PM or 10 lb/hr for other attainment pollutants if APCD has insufficient data to determine air quality effects; one year minimum pre-construction monitoring.
AQIA Exemptions	Construction results in emission reduction; replacement source constructed with BACT and no net emissions increase; fuel conversion from gas to oil due to gas shortage; essential public services; demonstrated air quality benefit; portable equipment used on temporary basis; innovative technology.	Demonstrated net air quality benefit; innovative control technology provided AQIA shows no violation or interference with standards or reasonable further progress for other emitted pollutants; cogeneration and resource recovery projects.	See AQIA.
BACT/Emission Trade-Off Exemptions	Exemption from BACT if its implementation results in source closure or non-construction for sources with net emissions increase ≥5 lb/hr but <10 lb/hr.	Current rule's exemption from BACT removed; cogeneration and resource recovery projects exempt from trade-offs to extent provided in Part 7 of proposed rule.	Sources exempt from BACT/trade-offs on pollutant by pollutant basis if no air quality standard or increment is violated based on Part 8 of proposed rule and source uses innovative technology; cogeneration and resource recovery projects exempt to extent provided in Part 7 of proposed rule.

A future possibility noted by the SBCAPCD is the redesignation of ozone from attainment to nonattainment status. If this occurred prior to permitting of new energy/commodity facilities, net emissions increases of reactive organic compounds (ROC) and NO_x would be reviewed under the proposed SBCAPCD NSR requirements. The SBCAPCD considers emissions of ROC and NO_x to be precursors of ozone. Therefore, if the area is nonattainment for ozone, then ROC and NO_x are considered nonattainment pollutants.

The dual definition of stationary source applies under the NSR requirements. That is, the SBCAPCD would review the project two ways: 1) the entire VAFB plus the energy/commodity facilities would be considered as one stationary source, and 2) the energy/commodity facilities alone would be reviewed as one stationary source. This dual definition review precludes a project from avoiding regulatory requirements due to net emissions decreases associated with other equipment and installations in the same overall stationary source. For example, a new instllation at a large facility may not require BACT based on the net emissions increases from the entire facility. However, the net emissions increases from the new installation alone could trigger the BACT requirements. In this case for nonattainment pollutants, BACT would be required on the new installation.

It should be noted that the NSR and PSD regulatory requirements are triggered on a pollutant by pollutant basis. That is, the proposed energy/commodity facilities could be reviewed under the NSR requirements for some pollutants and PSD requirements for other pollutants. Also, the requirement of BACT or emission offsets for one pollutant does not automatically trigger the same requirement for other pollutant emissions. Consequently, each pollutant emitted from the energy/commodity facilities must be reviewed individually to determine the regulatory requirements governing that pollutant.

The proposed SBCAPCD regulations will require emission offsets for net emissions increases of ROC, NO_x, SO_x, or PM that are greater than 10 lb/hr. Net emissions decreases may be available within VAFB through switching to cleaner fuels in boilers (e.g., diesel oil to natural gas) and/or the implementation of employee transportation plans to reduce mobile source emissions. The availability of emission offsets from sources outside of VAFB is not known. For energy/commodity technologies that will emit more than 10 lb/hr of ROC, NO_x, SO_x, or PM after control, the availability of emissions decreases or offsets could be a critical constraint to the project. However, determining the availability of potential emissions decreases within VAFB and offsets outside of VAFB was not in the scope of this study.

4.2.3 Air Pollution Control Technologies

The proposed SBCAPCD regulations require BACT for pollutants with net emissions increases equal to or greater than specified levels. These levels are 2.5 lb/hr for nonattainment pollutants and 5 lb/hr for attainment pollutants. Several of the candidate energy/commodity technologies will result in net emissions increases that trigger BACT requirements. BACT is defined as the more stringent of: 1) the most effective emission control device, emission limit, or technique which has been achieved in practice for the type of equipment in the stationary souce, or 2) any other emission control device or technique determined after public hearing to be technologically feasible and cost-effective by the Air Pollution Control Officer. Under no circumstances shall BACT be less stringent than the emission control required by any federal, state, or local regulations. Based on this definition, BACT is determined on a case-by-case basis. An applicant for a new or modified stationary source must investigate the most effective emission controls achieved in practice and/or required by other regulations as well as evaluate the cost-effectiveness of emission control candidates.

Table 4-5 presents candidate BACT methods for the energy/commodity options. This list was developed based on BACT lists from the South Coast Air Quality Management District (SCAQMD) and the Ventura County Air Pollution Control District (VCAPCD), communications with staff of the SBCAPCD, and engineering judgement. The SBCAPCD does not have a BACT list. However, BACT guidelines and policies are fairly consistent for California's APCDs and AQMDs. Therefore, Table 4-5 is expected to provide accurate guidance in determining candidate BACT methods for the energy/commodity technologies.

In Table 4-5, the energy/commodity technologies have one or more candidate BACT methods listed for each applicable pollutant. In particular, NO_x emissions from combustion technologies have several candidate BACT methods. The type of NO_x control method(s) eventually selected as BACT depends on the type and configuration of the combustion equipment, the type of fuel, and cost-effectiveness. Candidate NO_x control methods for combustion technologies include combustion modifications such as flue gas recirculation, staged combustion, low excess air, and derating; low NO_x burners (LNB), selective noncatalytic reduction (SNCR), and selective catalytic reduction (SCR). Of these, SCR provides the most effective NO_x emission control. However, SCR is also the most expensive and probably least cost-effective NO_x control method. The SBCAPCD indicated that SCR would probably not be required for coal or oil-fired boiler technologies at this time. However, the SCAQMD and VCAPCD include SCR for consideration on their respective BACT guidance lists. In fact, SCAQMD policy states that SCR or equivalent is required for all boilers and heaters larger than 50×10^6 Btu/hr provided that certain cost-effectiveness criteria are met. Consequently, SCR, although very stringent, is included as a candidate BACT method. However, no SCR is presumed for the systems considered in this study.

In general, the use of cleaner fuels such as natural gas will result in lower overall pollution control requirements in terms of cost, complexity, and the number of pollutants requiring control. Combustion technologies burning natural gas or lighter oils will primarily require emission control for NO_x.

TABLE 4-5. BEST AVAILABLE CONTROL TECHNOLOGY (BACT)

Technology	NO_x	SO_x	PM	Other Contaminants
(1) External Combustion (Boiler)/Steam Turbines				
• Coal fired	Combustion modifications, LNB[1], SNCR[2], and/or SCR[3] (approx. 80% eff)	AFBC[4], FGD[5], (90 + % eff) and/or low sulfur coal (cleaned or uncleaned)	Baghouse (99 + % eff) or ESP[6] (99 + % eff) and/or coal with low ash content	
• Oil fired	Combustion modification (50 to 60% eff), LNB, SNCR and/or SCR (approx. 80% eff)	Low sulfur fuel oils and/or FGD (90 to 95% eff)	Low ash fuel oils and/or ESP (90% eff)	
• Gas fired	Combustion modifications, LNB, SNCR, and/or SCR (70 to 90% eff)	Natural gas or low sulfur gas		
(2) Gas Turbines				
• Gas fired	Water or steam injection (approx. 80% eff)	Natural gas or low sulfur gas	No control	No control
• Oil fired	Water or steam injection (approx. 80% eff)	Low sulfur oil	No control	No control
(3) Combined Cycle Turbines				
• Gas generation	See coal gasification and partial oxidation	See coal gasification and partial oxidation	See coal gasification and partial oxidation	
• Turbines	See gas turbines	See gas turbines		
(4) Internal Combustion Engines				
• Gas fired	NSCR[7], SCR (90% eff) and/or combustion modification	Natural gas or low sulfur gas		CO and organics - NSCR
• Diesel fired	Combustion modifications	Low sulfur diesel		
(5) Coal Gasification				
• Coal storage, handling, and crushing/sizing			Dust suppressants, water sprays, enclosures, hoods	
• Coal feeding vent gases			Duct to product gases or eliminate	Organics - not determined

(continued)

TABLE 4-5. (continued)

Technology	NO_x	SO_x	PM	Other Contaminants
• Ash removal vent gases			Not determined	Organics - not determined
• Coal gasifier start-up vent stream			Not determined	Combustion - flare
• Sulfur recovery tail gas	No control	Tail gas cleanup	No control	H_2S - tail gas cleanup
• Fugitive emissions	NA[8]	NA	NA	Organics, H_2S, CO, other gas species - good leak detection & repair & engr. practices
• Expansion gases	NA	NA	NA	Same as Fugitive - duct to sulfur recovery, incineration
(6) Partial Oxidation	See coal gasification except for coal handling	See coal gasification except for coal handling	See coal gasification except for coal handling	See coal gasification except for coal handling
(7) Steam Reforming				
• Steam Reforming Furnace	See gas-fired boiler	See gas-fired boiler	See gas fired boiler	
(8) Hydrogen Liquefaction	NA	NA	NA	NA
(9) Electrolysis	NA	NA	NA	NA
(10) Air Separation	NA	NA	NA	NA
(11) Solar Central Receiver (Power Tower)	NA	NA	NA	NA
(12) Solar Photovoltaics	NA	NA	NA	NA
(13) Wind Turbines	NA	NA	NA	NA
(14) Fuel Cells				
• Power section	No control	No control	No control	No control
• Fuel processor	See coal gasification or steam reforming	See coal gasification or steam reforming	See coal gasification or steam reforming	-
(15) Commodities and Electricity Production	See individual technology components	See individual technology components	See indivitual technology components	See individual technology components

(continued)

TABLE 4-5. (continued)

Technology	NO_x	SO_x	PM	Other Contaminants
(16) Pumped Hydro	NA	NA	NA	NA
(17) Hydrogen Storage	NA	NA	NA	NA

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[1] LNB - low NO_x burner

[2] SNCR - selective noncatalytic reduction

[3] SCR - selective catalytic reduction

[4] AFBC - atmospheric fluidized bed combustion

[5] FGD - flue gas desulfurization

[6] ESP - electrostatic precipitator

[7] NSCR - nonselective catalytic reduction

[8] NA - not applicable

Combustion technologies that burn heavier oils or coal will require emission control for NO_x as well as SO_x and PM emissions.

4.3 WATER/WASTEWATER QUALITY CONSIDERATIONS

This section presents the water/wastewater quality considerations associated with the energy/commodity technology options. These considerations include the current water/wastewater treatment capabilities of VAFB and the water quality regulations governing wastewater discharges.

4.3.1 Current Operations at VAFB

Prior to 1979, VAFB operated a basic secondary wastewater treatment plant with discharge of treated wastes through an ocean outfall. The plant consisted of primary sedimentation, trickling filters, and anaerobic sludge digestion. In 1979, a new wastewater treatment plant started up in nearby Lompoc. This new plant has a capacity of five million gallons per day (mgd). Currently, the new plant handles approximately three mgd with about one mgd coming from VAFB. As a result, VAFB's wastewater treatment plant has been removed from active service and considerable renovation would be required to return the plant to operation. VAFB has package treatment plants associated with missile launch sites. These plants use extended aeration/activated sludge treatment methods with disposal of treated wastes to evaporation/percolation ponds. VAFB's radar sites have septic tank/leach line systems to treat and dispose of associated wastewaters. In conclusion, VAFB currently has no wastewater discharge to surface waters (e.g., the ocean, surface streams, etc.). However, VAFB does have existing wastewater discharges to land.

4.3.2 Water Quality Regulations

The Central Coast Regional Water Quality Control Board (RWQCB) is responsible for issuing water quality permits and enforcing water quality standards at VAFB. RWQCB policy encourages the reclamation/reuse of wastewater and waste disposal to land. Generally, waste discharge to surface waters is discouraged. Additionally, any surface discharges which would enter the ocean south of Point Arguello are prohibited by the RWQCB.

Waste discharges to surface waters require a permit under the federal National Pollutant Discharge Elimination System (NPDES). The RWQCB has authority to issue and enforce these NPDES permits. Waste discharge permits must be obtained from the RWQCB for waste discharges that may affect groundwater quality. An example of this would be waste discharge to an evaporation/percolation pond. Waste discharge limitations depend on the characteristics of the waste stream, method of waste treatment, and method of disposal. For example, waste discharge limitations for cooling water blowdown would be different from those for domestic sewage due to their dissimilar characteristics. Also, waste discharge limitations for discharges to the ocean would be different from those for discharges to land due to their unique water quality objectives. For any waste discharge, the RWQCB sets limitations to ensure that the discharge is consistent with all water quality standards and will not harm beneficial uses such as public water supplies, agricultural and industrial water use, wildlife habitats, or any water-related recreational activity. The RWQCB does not dictate specific treatment methods to meet discharge limitations.

Specific criteria and limitation guidelines are contained in the RWQCB's Water Quality Control Plan (i.e., Basin Plan). The Basin Plan links waste discharge limitations to the specific water quality objectives of the surface waters and groundwaters in the Central Coast Region. Discharges to the ocean must meet the criteria and limitations contained in the Water Quality Control Plan for Ocean Waters of California (i.e., Ocean Plan). It contains waste discharge limitations for bacteriological characteristics, grease and oil, suspended and settleable solids, turbidity, pH, toxicity concentration, and toxic substances. Table 4-6 presents the effluent quality requirements associated with the primary wastewater constituents for ocean discharges. Table 4-7 presents the effluent quality requirements associated with toxic materials in ocean discharges. Wastewater discharges to the ocean must meet the limitations in these tables.

In addition to the preceding criteria and limitations, the U. S. Environmental Protection Agency (EPA) has promulgated effluent limitations for the steam electric power generation point source category. These limitations will probably apply to waste streams for electrical power generation at VAFB. The RWQCB is responsible for applying and enforcing these limitations. New source performance standards (NSPS) would apply to surface water discharges. Pretreatment standards would apply to discharges to publicly owned treatment works (e.g., the Lompoc wastewater treatment plant). The types of waste streams regulated by the federal effluent limitations include:

- once-through cooling water,
- cooling tower blowdown,
- fly ash transport water,
- bottom ash transport water,
- chemical metal cleaning wastes,
- low volume wastes, and
- coal pile runoff.

4.3.3 Potential Wastewater Discharges

Several of the candidate energy/commodity technologies will result in wastewater streams that require treatment and/or disposal. In particular, technologies that use coal as a fuel or primary input material have the greatest potential for producing wastewater streams that require treatment and disposal. Table 4-8 presents the potential wastewater and solid waste streams from the energy/commodity technologies. The table is presented in Section 4.4

TABLE 4-6. EFFLUENT QUALITY REQUIREMENTS FOR PRIMARY WASTEWATER CONSTITUENTS IN OCEAN DISCHARGES

		Limiting Concentrations		
	Unit of measurement	Monthly (30 day Average)	Weekly (7 day Average)	Maximum at any time
Grease and Oil	mg/l	25	40	75
Suspended Solids	see below*			
Settleable Solids	mg/l	1.0	1.5	3.0
Turbidity	JTU	75	100	225
pH	units	within limits of 6.0 to 9.0 at all times		
Toxicity Concentration	tu	1.5	2.0	2.5

*Suspended Solids: Dischargers shall, as a 30-day average, remove 75% of suspended solids from the influent stream before discharging wastewaters to the ocean, except that the effluent limitation to be met shall not be lower than 60 mg/l. Regional Boards may, with the concurrence of the State Board and the Environmental Protection Agency, adjust the lower effluent concentration limit (the 60 mg/l above) to suit the environmental and effluent characteristics of the discharge. As a further consideration in making such adjustment, Regional Boards should evaluate effects on existing and potential water reclamation projects.

If the lower effluent concentration limit is adjusted by the Regional Board, the discharger shall remove 75% of suspended solids from the influent stream at any time the influent concentration exceeds four times such adjusted effluent limit.

TABLE 4-7. EFFLUENT QUALITY REQUIREMENTS FOR TOXIC CONSTITUENTS IN OCEAN DISCHARGES

	Limiting Concentrations			
	Unit of Measurement	6-Month Median	Daily Maximum	Instantaneous Maximum
Arsenic	ug/l	8	32	80
Cadmium	ug/l	3	12	30
Chromium (Hexavalent) (see below, a)	ug/l	2	8	20
Copper	ug/l	5	20	50
Lead	ug/l	8	32	80
Mercury	ug/l	0.14	0.56	1.4
Nickel	ug/l	20	80	200
Silver	ug/l	0.45	1.8	4.5
Zinc	ug/l	20	80	200
Cyanide	ug/l	5	20	50
Total Chlorine Residual	ug/l	2	11	126
(for intermittent chlorine sources, see below, b)				
Ammonia (expressed as nitrogen)	ug/l	600	2400	6000
Toxicity Concentration	tu	0.05	-	-
Phenolic Compounds (non-chlorinated)	ug/l	30	120	300
Chlorinated Phenolics	ug/l	1	4	10
Aldrin and Dieldrin	ug/l	0.002	0.004	0.006
Chlordane and Related Compounds	ug/l	0.003	0.006	0.009
DDT and Derivatives	ug/l	0.001	0.002	0.003
Endrin	ug/l	0.002	0.004	0.006
HCH	ug/l	0.004	0.008	0.012
PCBs	ug/l	0.003	0.006	0.009
Toxaphene	ug/l	0.007	0.014	0.021
Radioactivity	Not to exceed limits specified in Title 17, Chapter 5, Subchapter 4, Group 3, Article 3, Section 30269 of the California Administrative Code.			

a) Dischargers may at their option meet this limitation as a total chromium limitation.

b) Water quality objectives for total chlorine residual applying to intermittent discharges not exceeding two hours, shall be determined through the use of the following equation:

$$\log y = -0.33 (\log x) + 2.1$$

where: y = the water quality objective (in ug/l) to apply when chlorine is being discharged;
x = the duration of uninterrupted chlorine discharge in minutes.

TABLE 4-8. POTENTIAL WASTEWATER AND SOLID WASTE STREAMS

Technology	Waste Stream Description	Treatment and Disposal Comments
(1) External Combustion (Boiler)/ Steam Turbines		
• Coal fired	• Boiler ash	• Landfill - may be considered hazardous
	• FGD sludge	• Landfill - may be considered hazardous
	• Fly ash from particulate control systems	• Landfill - may be considered hazardous
	• Water runoff from coal storage, handling, and crushing/sizing	• Solids removal, solar evaporation - may be considered hazardous
	• Rock and mineral waste from coal crushing and sizing	• Landfill - may be considered hazardous
• Coal, oil or gas fired	• Boiler feedwater treatment sludge	• Landfill; containment pond
(2) Gas Turbines	• Water treatment system wastewater	• Solar evaporation; discharge to municipal treatment plant
(3) Combined Cycle Turbines		
• Gas Generation	• See coal gasification or partial oxidation	• See coal gasification or partial oxidation
• Turbines	• Water treatment system wastewater	• Solar evaporation; discharge to municipal treatment pland
	• Boiler feedwater treatment sludge	• Landfill; containment pond
(4) Internal Combustion Engines	• None or insignificant	
(5) Coal Gasification	• Water runoff from coal storage, handling, and crushing/sizing	• Solids removal, solar evaporation - may be considered hazardous
	• Rock and mineral waste from coal crushing and sizing	• Landfill - may be considered hazardous
	• Spent ash quench water from ash removal	• Suspended and dissolved solids removal; water recycling; solids disposal to landfill - may be considered hazardous
	• Gasifier ash or slag	• Landfill - may be considered hazardous
	• Collected particulate matter from gas purification	• Landfill - may be considered hazardous; use as fuel
	• Spent quench liquor from gas quenching and cooling	• Biological oxidation; ammonia removal; phenol removal; oil removal; water recycling
	• Spent sorbents and reactants from acid gas removal	• Resource recovery; landfill - may be considered hazardous
	• Spent catalysts	• Resource recovery; landfill - may be considered hazardous
	• Wastewater treatment sludges	• Landfills; containment ponds - may be considered hazardous
	• Cooling water system blowdown	• Solar evaporation; discharge to municipal treatment plant
	• Feedwater treatment sludge	• Landfill; containment pond
(6) Partial Oxidation	• See coal gasification except for coal handling	• See coal gasification
(7) Steam Reforming	• Spent catalysts and sorbents	• Resource recovery; landfill - may be considered hazardous
	• Boiler feedwater treatment sludge	• Landfill; containment pond
	• Water treatment system wastewater	• Solar evaporation; discharge to municipal treatment plant
(8) Hydrogen Liquefaction	• None or insignificant	
(9) Electrolysis	• None or insignificant	
(10) Air Separation	• None or insignificant	

(continued)

TABLE 4-8. (continued)

Technology	Waste Stream Description	Treatment and Disposal Comments
(11) Solar Central Receiver (Power Tower)	• Cooling water system blowdown • Feedwater treatment sludge	• Solar evaporation; discharge to municipal treatment plant • Landfill; containment pond
(12) Solar Photovoltaics	• None or insignificant	
(13) Wind Turbines	• None or insignificant	
(14) Fuel Cells		
• Fuel Processor	• See coal gasification or partial oxidation	• See coal gasification or partial oxidation
• Power Section	• None or insignificant	
(15) Commodities and Electricity Production	• See individual technology components	• See individual technology components
(16) Pumped Hydro	• None or insignificant	
(17) Hydrogen Storage (Liquid, Gas)	None or insignificant	

because it focuses more on solid wastes than on wastewater. The systems considered later in this report are designed to minimize or eliminate wastewater discharges. Extensive wastewater treatment is obviously required for some wastewater streams.

4.4 SOLID WASTE CONSIDERATIONS

This section presents the solid waste considerations associated with the energy/commodity technology options. These considerations include the current solid waste handling methods at VAFB and the applicable regulations governing solid wastes.

4.4.1 Current Operations at VAFB

VAFB operates a Class II-2 landfill on the base. This type of landfill can accept Group 2 and 3 wastes. Group 2 wastes include chemically or biologically decomposable materials but do not include toxic materials. Group 3 wastes are entirely nonwater-soluble materials and nondecomposable, inert materials. Hazardous, or Group 1 wastes cannot be disposed in VAFB's landfill. The Casmalia waste disposal site, approximately 10 to 15 miles from VAFB, accepts hazardous Group 1 materials.

A group within the Department of Defense, the Defense Logistics Agency, has responsibility for contracting the handling of hazardous wastes at VAFB. Hazardous wastes are transported off-site by certified haulers for either resource recovery or disposal. Comprehensive hazardous waste manifest records are kept for the California Department of Health Services (DHS). VAFB currently has interim permit status for the storage of hazardous wastes. However, the DHS is soon expected to ask VAFB to submit a comprehensive application for a hazardous waste storage facility. VAFB does not treat or dispose of hazardous waste.

4.4.2 Regulations Governing Solid Wastes

The RWQCB governs groundwater aspects of the disposal of solid wastes to land. VAFB must comply with site-specific waste discharge requirements from the RWQCB for the operation of their Class II-2 landfill. These waste discharge requirements are designed to protect the groundwater quality and still allow disposal of applicable wastes. Similar to the discharge of wastewater to land, new land discharges of solid wastes must obtain and comply with site-specific waste discharge requirements from the RWQCB. The Basin Plan contains the criteria and guidelines from which the site-specific waste discharge requirements are developed.

The RWQCB, DHS, and EPA all currently govern hazardous waste management practices in California. However, proposed regulations by the DHS and the State Water Resources Control Board (SWRCB) would give California complete hazardous waste management authority and preclude the need for EPA involvement. These regulations would require facilities that store, treat, and/or dispose of hazardous wastes to obtain a hazardous waste facility permit and comply with a complex set of regulatory provisions. These proposed regulations are at least as stringent as EPA's Resource Conservation and Recovery Act (RCRA) requirements, and in many cases, more stringent.

The current and proposed hazardous waste management regulations in California are very complex. Proposed regulations are currently the subject of public hearings and could be modified several times prior to final adoption.

4.4.3 Potential Solid Waste Discharges

Table 4-8 presents potential wastewater and solid waste streams from the energy/commodity options. As shown, many of the energy/commodity technologies will result in solid waste streams that require treatment and/or disposal. This is particularly true for technologies that involve the combustion of coal. Under existing regulations, many of the solid waste streams may be considered hazardous such as waste from coal crushing and sizing, ash from coal combustion, and wastes from pollution control systems. If VAFB has energy/commodity facilities that generate hazardous wastes, VAFB will need to treat and/or dispose of these wastes on base or have the wastes transported off base for treatment and/or disposal. VAFB currently disposes its hazardous wastes off base. Generation of additional hazardous wastes would result in increased manifesting requirements and costs for off base disposal. The proposed SWRCB land disposal regulations have provisions to classify ash from fossil-fuel combustion as "monotype" wastes. This classification could allow ash to be disposed of in sites other than hazardous wastes disposal sites. However, the proposed DHS hazardous waste management regulations currently do not have similar provisions.

In general, the use of natural gas will minimize the generation of wastewater and solid waste streams that require treatment and disposal. The use of fuels such as coal will result in wastewater and solid waste streams that require more complex and costly treatment and disposal. Compliance with the current and proposed hazardous waste management requirements is extremely costly. Treatment costs will be minimized if clean fuels are used for the energy/commodity technologies.

4.5 CONCLUSIONS

This section presents conclusions associated with the evaluation of environmental considerations for candidate VAFB energy/commodity technologies.

4.5.1 Regulatory Agencies

- The Santa Barbara County Air Pollution Control District (SBCAPCD) and the California Regional Water Quality Control Board (CRWQCB) will have the primary environmental permitting responsibilities for the energy/commodity technologies.

- Environmental regulatory agencies that are expected to have little or no involvement in permitting the VAFB energy/commodity technologies include the Environmental Protection Agency (EPA), California Department of Health

Services (DHS), Santa Barbara County Resources Management Department (SBCRMD), California Coastal Commission (CCC), California Energy Commission (CEC), and the California Public Utilities Commissions (CPUC).

- The RWQCB governs groundwater aspects of the discharge of solid wastes to landfills. However, the CRWQCB, DHS, and EPA all currently have regulatory programs associated with the treatment and disposal of hazardous wastes. The State Water Resources Control Board (SWRCB) and the DHS are proposing major revisions to California's hazardous waste management regulations in order to obtain authority to regulate hazardous waste management in California.

4.5.2 Attainment Status

- VAFB is currently in an area that is in attainment for all ambient air quality standards.
- If the VAFB area maintains its attainment status, proposed energy/commodity technologies will be reviewed under the imminent SBCAPCD Prevention of Significant Deterioration (PSD) requirements.
- The availability of emissions decreases or offsets was not determined in this study but could be a critical constraint to certain energy/commodity technologies.

4.5.3 Technology Considerations

- For energy/commodity technologies involving fuel combustion, the use of cleaner fuels such as natural gas will result in lower overall air pollution control requirements in terms of cost, complexity, and the number of pollutants requiring control.
- For energy/commodity technologies that produce wastewater streams, the primary options for discharge and disposal are discharge to land, and discharge to the existing Lompoc wastewater treatment plant. Both of these options have capacity limitations.
- For energy/commodity technologies involving fuel combustion, the use of cleaner fuels such as natural gas will minimize the cost and complexity of wastewater treatment and disposal. In particular, wastewater streams from coal conversion technologies will require complex treatment to meet requirements for land discharge.

- For energy/commodity facilities involving fuel combustion, the use of cleaner fuels such as natural gas will minimize the amount of solid waste that must be handled and disposed of.

- If energy/commodity technologies produce wastes that are considered hazardous (e.g., possibly coal combustion ash, pollution control system wastes), the waste manifesting and disposal costs for VAFB could increase substantially.

Section 5

ENERGY AND COMMODITY PRICE FORECASTS

Price forecasts are required for the economic evaluation of options for producing electricity and commodities at VAFB. In this section, industrial sector energy prices are forecasted for electricity, coal, natural gas and crude, residual and distillate oils. Prices are also forecasted for the commodities hydrogen, oxygen, and nitrogen.

Section 5.1 discusses industrial energy price forecasts for California and the United States. These projections are the basis for forecasting the prices of liquid hydrogen, liquid oxygen, and liquid nitrogen. Section 5.2 details the projected hydrogen prices for 1983 through 2010, and Section 5.3 forecasts prices for oxygen and nitrogen for the same period. Prices for the three commodities depend heavily on the prices of electricity and/or natural gas, as is illustrated by a move in 1980 by one producer to tie industrial gas prices to energy price changes (5-1).

5.1 ENERGY PRICE FORECASTS

To provide a base case for this analysis, Radian examined three long-range, integrated energy price forecasts. The forecast by Data Resources, Inc. (DRI) was selected as the most appropriate on the basis of its scope and forecast period. The other forecasts reviewed were the Energy Information Administration's (EIA) 1982 Annual Energy Outlook (5-2) and the Office of Policy, Planning and Analysis' (OPPA) Energy Projections to the Year 2010(5-3).

The EIA study does not extend beyond 1990, making it an unsuitable base for 30-year projections. The OPPA study is not regionalized, whereas DRI provides forecasts for the Southern Pacific region, which is California. A regional forecast is desirable because California electric utilities use far less coal and more gas than the average utility. DRI meets the requirements for a long- term, regional study which is frequently updated and widely used. The Spring and Summer 1983 DRI forecasts (5-4, 5-5) were used as the basis for projecting energy prices to the year 2010.

The energy price forecasts in this report are used to indicate future relative prices. Because of uncertainty and complexity in energy markets and the economy, it is difficult to forecast energy prices with precision. For the economic analysis of technologies, the future relative prices are important. High and low bounds for energy prices have been included in this analysis in order to illustrate the uncertainty in the forecasts. In Sections 5.2 and 5.3, these bounds are incorporated into the commodity pricing scenarios.

Prices for 1983 are based on actual price information from California utilities, agencies and EIA reports. The DRI 1983 prices are estimates and not actual figures. Actual prices reported by utilities were used when possible because they provide the most timely and accurate information on prices paid by California industries for energy. Prices paid by industries for natural gas in 1983 were 38 percent higher than the prices estimated in the DRI summer review.

Prices in this study are based on constant value 1983 dollars. This is a departure from DRI's price projections, which are in nominal (inflated) dollars. For the mid-range scenario, DRI figures were adjusted for inflation at 6.1 percent per year for 1982-1990 and 6 percent per year through 2005. Projecting real price changes is more straightforward since it avoids the complexities of predicting long- term inflation rates. DRI's real percentage change between its 1983 prices and later years is applied to the actual 1983 prices to generate the prices for the mid-range scenarios. The use of actual versus estimated 1983 prices and real versus nominal price increases accounts for differences between the results of this study and the DRI summer report.

In addition to the mid-range projections, sceuarios for high and low prices were constructed for electricity, natural gas and crude oil. The high and low scenarios for electricity and natural gas prices are the result of varying the mid-range price of crude oil by 113 percent (for the high scenario) and 64 percent (for the low scenario). In the low scenario, crude oil prices grow at a real rate of 3.4 pecent annually, for a nominal growth rate of 9.8 percent per year. The high scenario results from a real 7.7 percent increase per year in the price of composite crude oil or a 14.4 percent nominal price increase per year. DRI contains high and low scenarios for national projections to the year 1990. Trends are assumed to continue beyond 1990 in order to establish bounds on 2000 and 2010 prices. As DRI does not publish regional high and low scenarios, the national high and low scenarios for electricity and natural gas are regionalized to provide an indication of price ranges which could be expected in California.

5.1.1 California Energy Prices

Figure 5-1 displays the price in dollars per million Btu for coal, electricity, fuel oil, crude oil and natural gas for California industries. In general, prices are not expected to rise until the late 1980s. This is a departure from the last decade, and reflects to some degree the effects of the 1982-83 recession. Each energy forecast is described in more detail below.

5.1.1.1 Methodology--Energy prices were projected using the following steps:

Step 1 - Base 1983 prices were determined for electricity, natural gas, coal, and oil in California. Sources of data were the California Energy Commission, Southern California Gas (SCG), Southern California Edison (SCE), Pacific Gas and Electric (PG&E), and EIA publications.

Step 2 - Real price changes in DRI forecases were calculated by subtracting inflation-caused price increases from the DRI forecasts. DRI

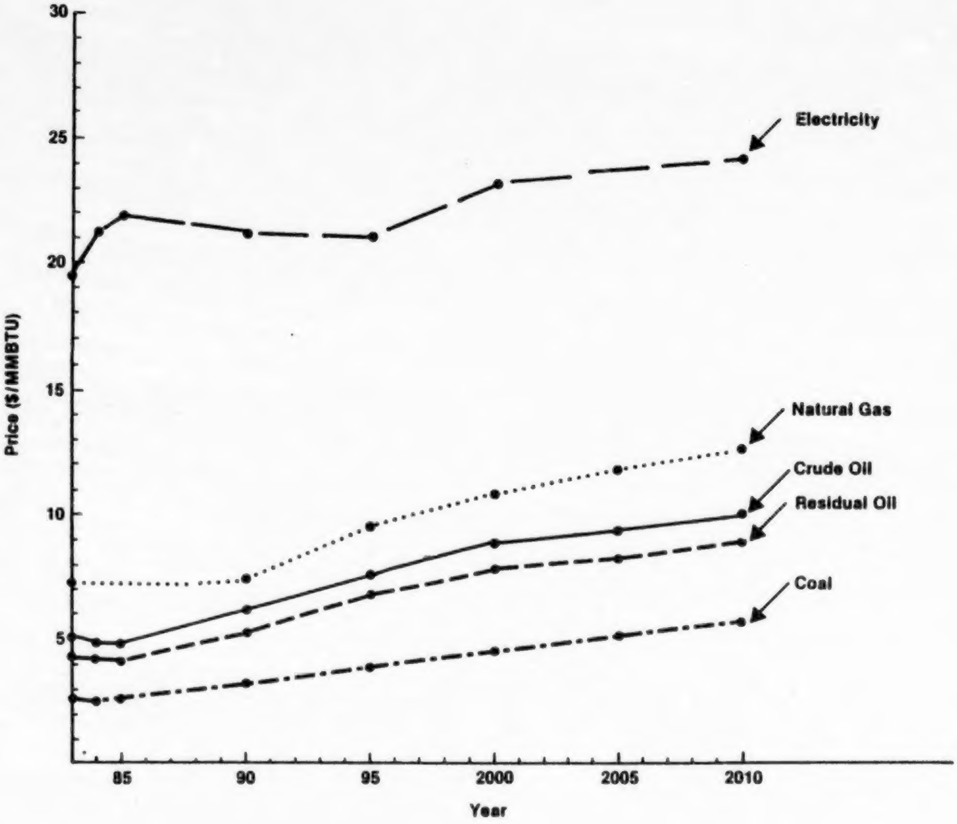


Figure 5-1. California industrial energy price forecast (1983 $)

assumes 6.1 percent per year inflation in the 1980s and 6 percent per year thereafter.

Step 3 - Real price changes calculated in Step 2 were applied to the actual 1983 prices from Step 1 in order to generate a mid-range price forecast. The percent change from 2000-2005 in DRI was extended to 2005-2010.

As DRI only publishes high and low price scenarios for the nation, regional high and low scenarios were extrapolated from the DRI national price scenarios. This involved two additional steps.

Step 4 - The difference between the DRI national high- and mid-range scenario prices and the difference between the DRI national mid-range and low scenario prices were calculated for each forecast year.

Step 5 - The two ratios from Step 4 are multiplied by the mid-range prices from Step 3 to yield high and low scenarios for the California region. For example, if the DRI high scenario price for oil in 1990 was 130 percent higher than the mid-range oil price, the mide-range 1990 oil price for California would be multiplied by 130 percent.

5.1.1.2 Electricity--Table 5-1 depicts the average industrial electricity price for the two utilities which serve Long Beach and Ontario, California, and VAFB. Long Beach and Ontario industries purchase power from Southern California Edison (SCE). Hydrogen producers are located in Long Beach and Ontario (5-6). VAFB buys electricity from Pacific Gas and Electric (PG&E).

TABLE 5-1. CALIFORNIA ELECTRICITY PRICE PROJECTIONS BY YEAR (in 1983 dollars)

Units	1983	1984	1985	1990	1995	2000	2010
\$/kWh	0.0665	0.0724	0.0745	0.0722	0.0721	0.0778	0.0814
$\$/10^6$Btu	19.48	21.21	21.83	21.15	21.12	22.79	23.85

A single average price for PG&E's and SCE's industrial electricity is used as the 1983 base price. Currently, SCE's price if 0.0706 $/kWh and PG&E's price is 0.065 $/kWh. However, historical price data do not support the premise that prices would remain different or that SCE would always charge more for electricity than PG&E. Figure 5-2 illustrates both utilities' prices for industrial electricity since 1973. Also shown is the mid-range projected price for electricity.

The average industrial electricity price for the two utilities is 0.0665 $/kWh. DRI projects a real increase of 12 percent by 1985. SCE's requested rate increase of 8.6 percent, for April 1984, supports the DRI projection (5-7). After 1985, real prices level off until 1995. There is another large increase of 7.8 percent from 1995 to 2000, followed by modest increases of 2.3 percent per five-year period.

High and low scenario prices are listed in Table 5-2. The low scenario shows a decline in real prices over time. The high scenario forecast prices are 123 percent higher in 2010 than the mid-range prices. This is the result of annual real price increases of 1.9 percent in the national high scenario and 1.1 percent in the national mid-range scenario.

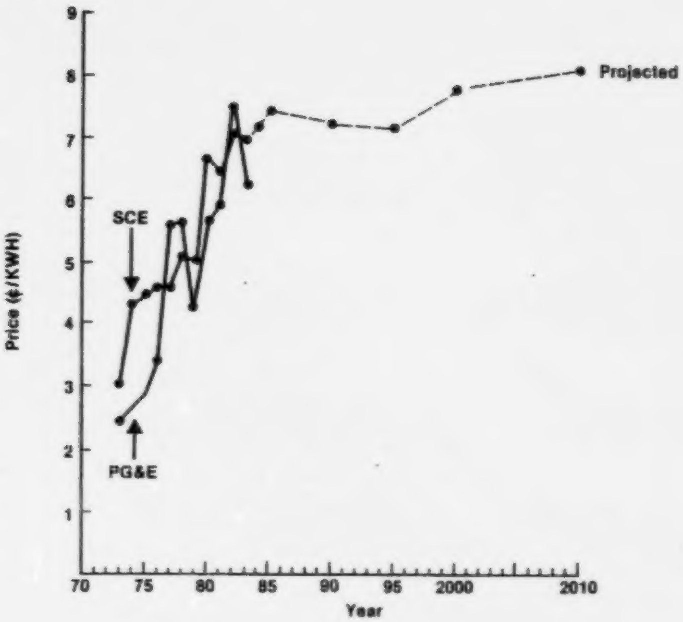


Figure 5-2. California electricity prices (1983 $)

TABLE 5-2. CALIFORNIA INDUSTRIAL ELECTRICITY PRICE SCENARIOS (in 1983 dollars, $/kWh)

Scenario	1983	1985	1990	2000	2010
Mid-Range	0.0665	0.0745	0.0722	0.0778	0.0814
Low	0.0665	0.0730	0.0671	0.0646	0.0602
High	0.0665	0.0760	0.0765	0.0887	0.1009

5.1.1.3 Natural Gas--Projected prices for Southern California Gas (SCG) industrial purchasers are included in Table 5-3. SCG sells gas to VAFB and Ontario directly.

TABLE 5-3. NATURAL GAS PROJECTIONS: SOUTHERN CALIFORNIA GAS (in 1983 dollars, $/$10^6$Btu)

Scenario	1983[1]	1985	1990	1995	2000	2010
Mid-Range	7.18	7.18	7.47	9.52	10.90	12.64
Low	7.18	6.91	7.36	9.23	10.46	11.25
High	7.18	7.31	7.70	9.90	11.53	13.73

[1] Source: California Energy Commission and Soutern California Gas, Category 2a.

The city of Long Beach purchases gas from SCG and resells it. SCG's industrial category 2a price for natural gas is 7.18 $/$10^6$ Btu. The 2a category covers industries which use natural gas as a feedstock and are non-interruptible. In the opinion of California Energy Commission staff and SCG, hydrogen producers are included in the 2a category (Susan Garfield, California Energy Commission, personal communications; Paul Wirkowitz, SCG, personal communication).

The price of natural gas is constrained to a 4 percent rise by 1990. DRI called for a greater increase, but this resulted in natural gas prices in 2010 which were unrealistically high when compared to the prices of substitute fuels. Also, state projections do not forecast large rises in natural gas prices until after 1990 (Bill Wood, California Energy Commission, personal communication). The California Energy Commission has projected natural gas price rises of about 4 percent by 1990 and this figure has been used in the Radian projections. After 1990, the DRI real price changes are used to forecast future prices.

The mid-range forecast gas price is $\$12.64/10^6$ Btu in 2010. Table 5-3 lists the high and low price scenarios for natural gas. Figure 5-3 shows natural gas prices from 1978 to 2010.

5.1.1.4 Coal, Fuel Oil and Crude Oil Prices--Prices for coal and oil are projected for California, rather than on the basis of a utility service area. Coal prices are expected to remain flat until 1985, then increase rapidly until 2000. After 2000, real prices continue to increase at 11.9 percent for each five-year period. Table 5-4 provides details of projected coal prices.

Residual, distillate, and crude oil show the same percentage increases. Table 5-4 lists prices for fuel oils and crude oil. The price in $\$/10^6$ Btu for crude oil is always slightly higher than the price for residual fuel oil. As with other energy prices, crude and fuel oil prices are expected to decline until 1985, and then jump 25 percent by 1990. Five-year increases of 17 to 19 percent will occur in the 1990s, with increases of 7 percent every five years

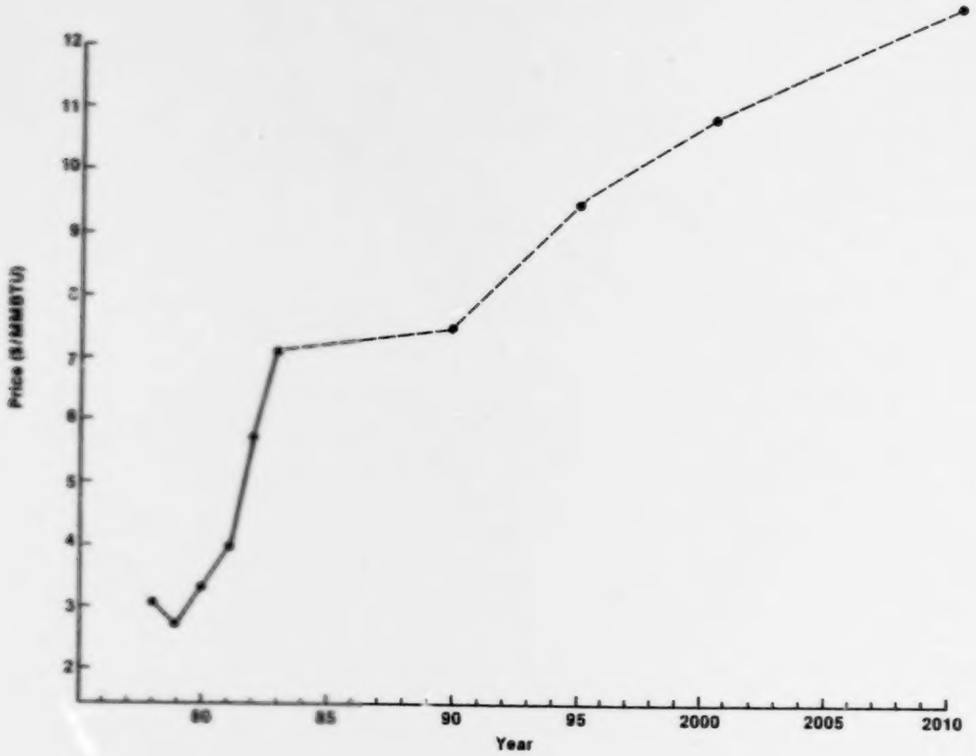


Figure 5-3. California natural gas prices (1983 $)

TABLE 5-4. CALIFORNIA PRICE PROJECTIONS FOR COAL, DISTILLATE, RESIDUAL AND CRUDE OIL (in 1983 dollars)

	Price, $\$/10^6$ Btu							
	1983	1984	1985	1990	1995	2000	2005	2010
Coal (delivered)	2.65[1]	2.59	2.72	3.17	3.97	4.51	5.06	5.65
Residual Fuel Oil	4.07[2]	4.00	4.01	5.04	5.88	6.88	7.33	7.80
Crude Oil	5.00[3]	4.89	4.87	6.12	7.53	8.80	9.38	10.00
Distillate	6.10[4]	5.97	5.95	7.47	9.19	10.74	11.44	12.20

Source:

[1] Quarterly Coal Report, October 1983, EIA.

[2] Petroleum Marketing Monthly, July 1983. Price paid in PAD District V by end users for residual greater than 1% sulfur.

[3] Annual Energy Review, August 1983, EIA.

[4] Petroleum Marketing Monthly, July 1983, EIA.

after the year 2000. Table 5-5 shows the high- and low-range scenarios for crude oil through the year 2010.

TABLE 5-5. CRUDE OIL SCENARIOS (in 1983 dollars, $\$/10^6$ Btu)

Scenario	1983	1990	2000	2010
Mid-Range	5.00	6.12	8.80	10.00
Low	5.00	4.41	5.02	4.60
High	5.00	7.71	12.58	16.30

For coal and fuel oils, the DRI estimated prices were very close to the actual reported prices. Reported prices were used as the 1983 baseline price for the scenarios.

5.1.2 National Electricity Prices

National electricity price forecasts are needed in order to project the standard prices of liquified oxygen and nitrogen. Unlike liquid hydrogen which is bought on the West Coast in a separate bid, nitrogen and oxygen users in the Air Force are charged a standard price across the United States. Thus, a national average industrial price for electricity is needed for forecasting. Oxygen and nitrogen forecasts and markets are discussed in more detail in Section 5.3

DOE's September Monthly Energy Review reports an average price paid by the industrial sector of \$0.0496/kWh. DRI estimated the national average electricity price to be \$0.058/kWh and that the national average electricity will increase 1.1 percent per year until 1990. This study assumes that electricity prices continue to rise 1.1 percent annually until 2010, for a price in 2010 of \$0.0666/kWh. This price is eqivalent to the OPPA's projected national electricity price of \$0.0673/kWh (1983 dollars). The lower and upper bounds on the 2010 price are \$0.0493 and \$0.0826/kWh. Table 5-6 lists the mid-range and bounds for electricity prices from 1983-2010.

TABLE 5-6. NATIONAL ELECTRICITY PRICE FORECAST
(1983 dollars, \$/kWh)

Scenario	1983	1985	1990	1995	2000	2010
Mid-Range	0.0496[1]	0.0507	0.0535	0.0566	0.0597	0.0666
Low	0.0496	0.0497	0.0598	0.0496	0.0496	0.0493
High	0.0496	0.0517	0.0567	0.0623	0.0681	0.0826

[1] Source: Monthly Energy Review, September 1983.

Electricity is the only significant energy source used for oxygen and nitrogen production and liquefaction (5-8, 5-9).

5.2 LIQUID HYDROGEN PRICE FORECAST

This section discusses liquid hydrogen markets and production, describes the methodology used for price forecasting and presents hydrogen price projections to the year 2010.

5.2.1 Background

5.2.1.1 Producers--The merchant liquid hydrogen market is dominated by three producers: Air Products, Union Carbide-Linde, and to a lesser extent, Airco (5-10). The three companies supply 90 percent of the merchant gas market. Liquid hydrogen production capacity for 1982 was estimated at 178 tons per day. Table 5-7 shows the producers, locations, and estimated plant capacities for 1982. Most of the plants were built to provide hydrogen to the aerospace program in the 1960s and the space shuttle program in the 1970s (5-6). Relocation of space program activities from California to the Southeast in the 1960s left many producers far from their traditional markets. Figure 5-4 illustrates the changing relationship between producer and consumer.

Most of the merchant hydrogen is produced via the steam reforming method, using natural gas as a feedstock. The Bureau of Census defines merchant hydrogen as gaseous hydrogen produced for cylinder and bulk delivery plus liquid hydrogen produced for conversion to gas (5-6). Liquid hydrogen accounts for 85 percent of the merchant hydrogen produced (5-12).

Merchant hydrogen production represents approximately one percent of total hydrogen production in the United States (5-12). Most hydrogen is produced as a result of chemical manufacturing and oil refining (5-13). These two industries also consume most of the hydrogen produced. Figure 5-5 shows hydrogen's demand pattern for 1981. Data for on-site production and consumption are generally regarded as incomplete.

The merchant hydrogen market is undergoing a change due to several factors affecting both supply and demand. One factor is the rising price of natural gas, which is encouraging producers to look at other feedstocks and processes. The demand for a very high purity hydrogen is creating a specialty market in which users will pay a premium for quality. Additionally, large users such as refineries, who have previously met their needs internally, have recently turned to merchant producers to meet their increased demand. Hydrogen producers are increasing their capacity and competing to increase

TABLE 5-7. PRODUCERS AND CAPACITIES - LIQUID HYDROGEN (tons per day)

Producer	Location	1982 Capacity
Air Products	New Orleans, Louisiana	60*
Air Products	Long Beach, California	30
Air Products	Sarnia, Ontario, Canada	15
Union Carbide-Linde	Ashtabula, Ohio	17
Union Carbide-Linde	Niagara Falls, New York	20
Union Carbide-Linde	Ontario, California	30
Airco	Pedricktown, New Jersey	6
Total		178

*2 plants.

Sources: References 5-6 and 5-11.

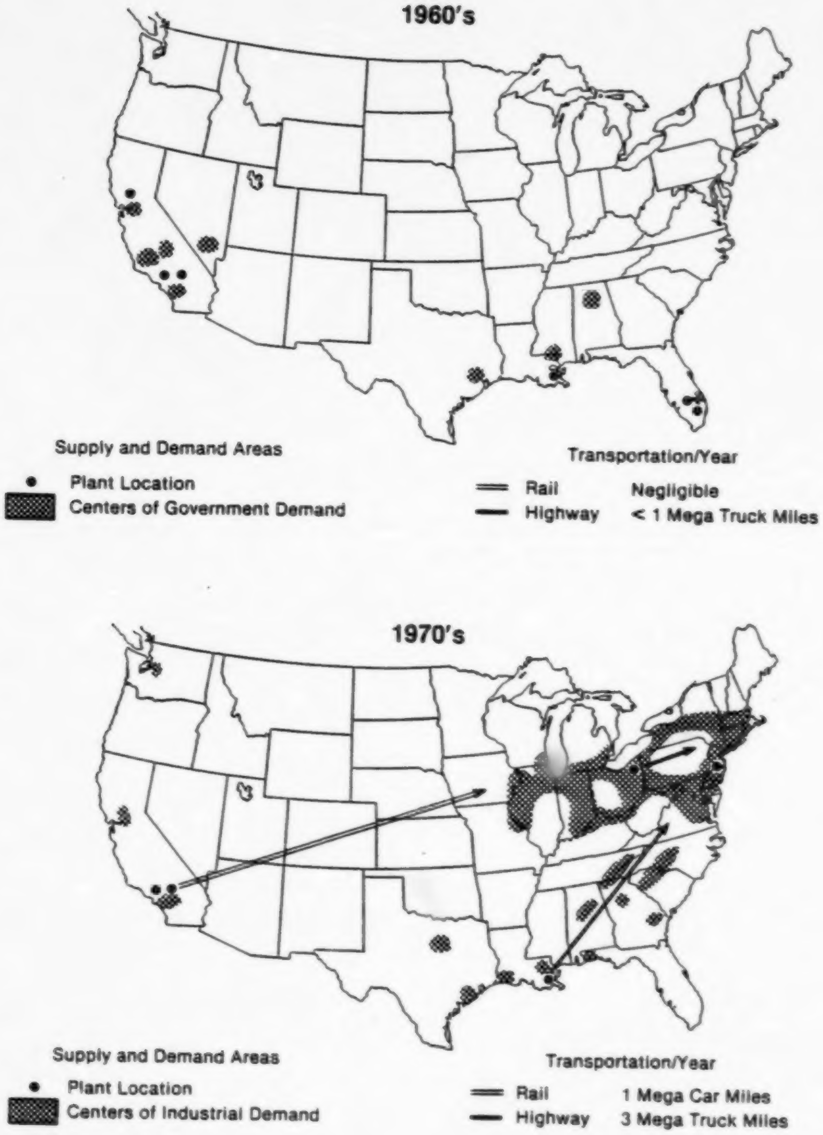
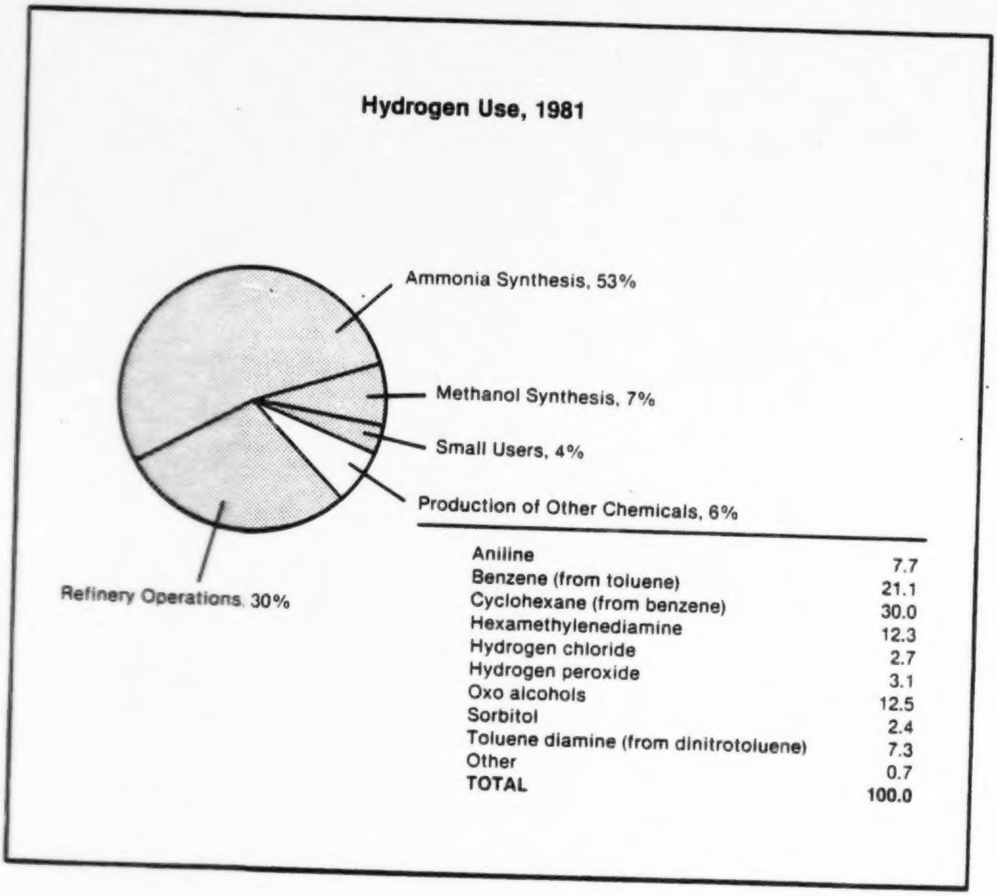

1960's
Supply and Demand Areas
● Plant Location
▨ Centers of Government Demand
Transportation/Year
═ Rail Negligible
— Highway < 1 Mega Truck Miles
1970's
Supply and Demand Areas
● Plant Location
▨ Centers of Industrial Demand
Transportation/Year
═ Rail 1 Mega Car Miles
— Highway 3 Mega Truck Miles

Figure 5-4. Location of hydrogen demand and supply

Source: John E. Johnson, "Commodity Hydrogen Production and Marketing," presented at Institute of Gas Technology Hydrogen Pricing Symposium, Chicago, Il, July 25, 1978, as shown in Reference 5-10.



Production of Other Chemicals, 6%	
Aniline	7.7
Benzene (from toluene)	21.1
Cyclohexane (from benzene)	30.0
Hexamethylenediamine	12.3
Hydrogen chloride	2.7
Hydrogen peroxide	3.1
Oxo alcohols	12.5
Sorbitol	2.4
Toluene diamine (from dinitrotoluene)	7.3
Other	0.7
TOTAL	**100.0**

Figure 5-5. Hydrogen demand pattern (1981)

Source: Stanford Research Institute and US Commerce Dept., as shown in Reference 5-12.

merchant hydrogen's share of the hydrogen produced. All of this is resulting in increasing price pressure in the merchant market (5-12).

The price of hydrogen is a function of volume. Small users pay a premium, since handling and transportation fees are a large part of the price they pay. With increased volume, transportation costs are reduced, either through the use of tube trailers for bulk delivery or liquifaction of the gas before delivery (5-13).

5.2.1.2 Markets and Uses--As shown in Figure 5-5, hydrogen is used in the production of ammonia, methanol, gasoline, chemicals and in the metallurgy, electronics, food and aerospace industries (5-6). Figure 5-6 shows the demand pattern for merchant hydrogen in 1977. Absent from the merchant users, until recently, are the big users, such as refineries and ammonia synthesis plants. Hydrogen is used in the space program as a fuel, because of its high energy content. In 1977, aerospace uses accounted for less than 10 percent of merchant hydrogen demand and less than one tenth of a percent of total hydrogen demand.

Hydrogen demand has almost doubled since 1971. Table 5-8 shows hydrogen production from 1971-1981. Production increases were not even across all categories. For example, pipeline shipment and government use almost tripled, whereas in-plant consumption did not double. However, the in-plant production figures may actually be twice that reported (5-12). Production for all categories reached a peak in 1980. However, the outlook for growth in the demand for hydrogen is good due to several trends: 1) tighter regulations on sulfur oxide emissions, 2) the increased refining of high-sulfur crude oils, and 3) the rapid growth of the electronics industry. Historal price data for West Coast liquid hydrogen purchased by the government are available for 1980-1983. This does not allow a lengthy comparison of energy prices versus hydrogen prices. More information is available on the commercial price of liquid hydrogen on the West Coast. Figure 5-7 shows the prices of government and commercial West Coast hydrogen, electricity and natural gas in 1983

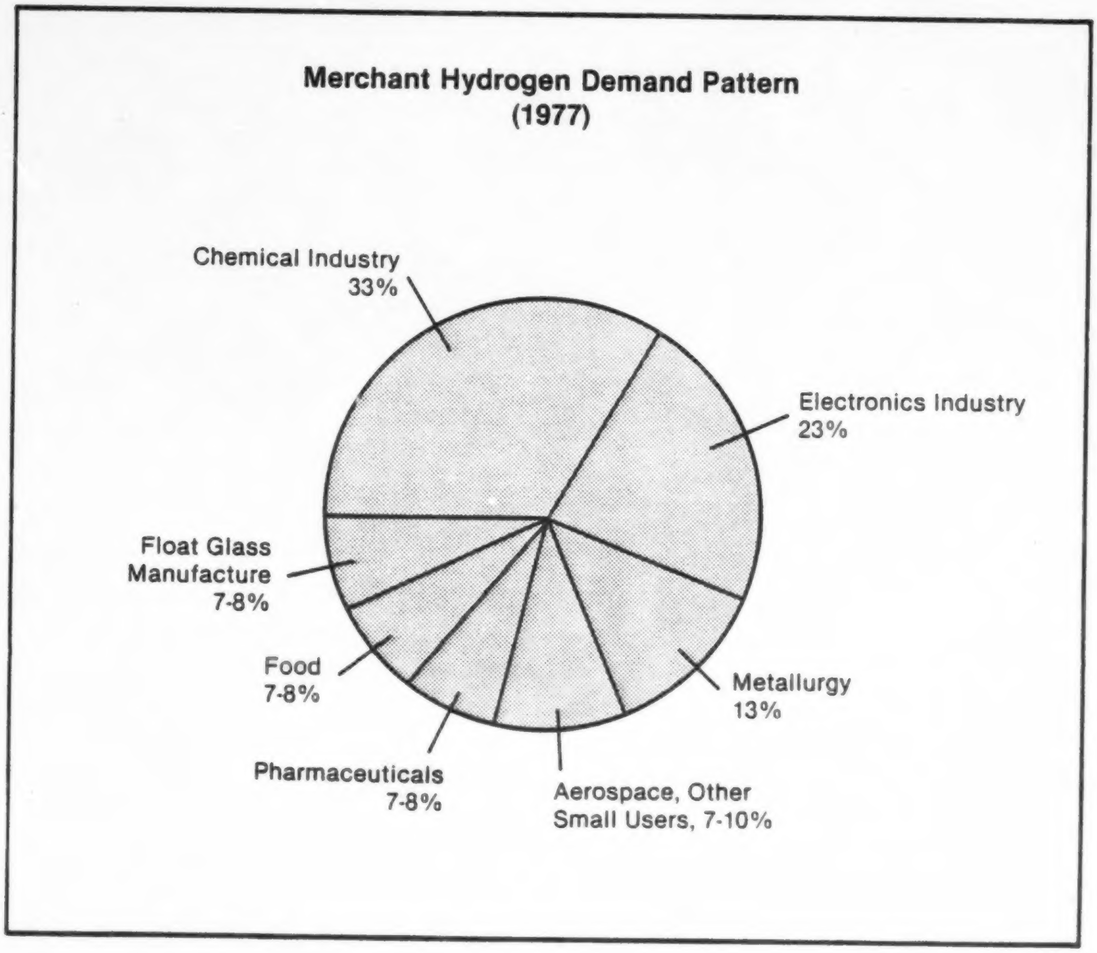


Figure 5-6. Merchant hydrogen demand pattern (1977)

Source: Reference 5-10.

TABLE 5-8. HYDROGEN PRODUCTION
(million cubic feet)

Hydrogen	Production[1]										
	1971	1972	1973	1974	1975	1976	1977	1978	1979	1980	1981
Liquid & Gas Cylinder, and Bulk Delivery & for Conversion to Gas	5,321	4,755	5,666	7,455	6,882	8,472	9,278	10,680	11,874	11,731	11,510
Pipeline Shipment & Government Use	12,321	13,539	13,148	21,860	20,780	23,905	25,975	28,041	33,038	39,522	35,944
In-plant Consumption	38,015	40,596	46,541	52,221	45,890	49,722	49,206	51,749	54,359	55,309	54,107
TOTAL	55,639	58,890	65,355	81,536	73,552	82,099	84,459	90,470	99,271	106,562	101,561

[1] Excludes amounts vented, used as fuel, used in manufacture of synthetic ammonia and methanol, produced by ammonia dissociation, and in petroleum refineries.

Source: Reference 5-14.

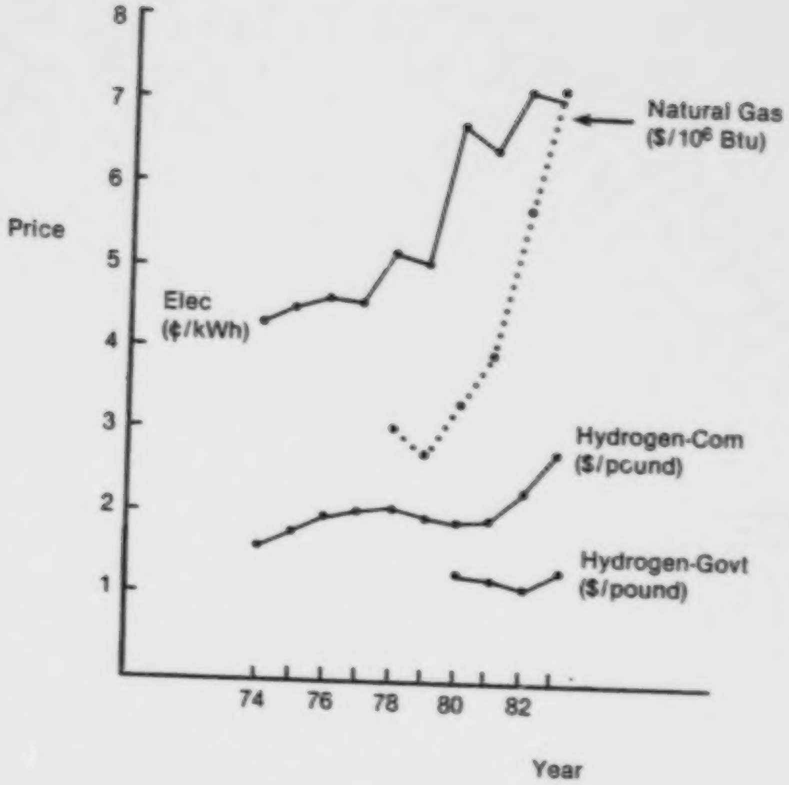


Figure 5-7. Prices of government and commercial liquid hydrogen

dollars. Electricity and natural gas prices soared after 1979. In 1980, the West Coast producers began adding an energy surcharge into the price of commercial hydrogen. This surcharge is reflected in the increasing commercial hydrogen price after 1981. For one producer in 1983, the energy surcharge amounted to $0.65/pound, in addition to a list price of $2.53/pound. The energy surcharge, which is 25 percent of the list price in 1983, is not included in the government price (Dave Cowling, Air Products and Chemicals, 1983, personal communication).

A comparison of prices for the years 1980-1983 illustrates the difficulty in forecasting hydrogen prices for the West Coast. Since there are only two producers, the market is extremely sensitive to the pricing of either producer. Government contracts, which are awarded every two years, are based on sealed bids. In 1982 and 1983, the price paid was affected by this bidding process. In order to assure the continuance of the contract, the producer with the 1980-1981 contract bid a price under its 1980 price (in real dollars). It took until February 1983 for the price to reach its 1980 level. Given increasing energy costs, this pricing behavior reflects a premium the producer is willing to "pay" in order to secure the government contract. One would expect the price to react dramatically if one of the producers left the market or if it became less attractive to secure the government contract, which could occur with an enhanced commercial market.

The lack of an historical data record also presents a problem. The short data record for the government contract prices does not allow one to generalize about either the relationship between commercial and government prices or energy and government prices.

5.2.2 Methodology

The liquid hydrogen forecasts are based on allocating the 1980-83 price into its non-energy and energy cost components. The energy cost component is escalated by the real projected price increases in natural gas and electricity, discussed in Section 5.1. Non-energy costs, which include non-fuel variable costs, labor, maintenance and fixed costs, are assumed to remain constant for the forecast period. Transportation costs, which are added to the plant price, are also assumed to remain constant in real terms.

Data for the projections include: government contract West Coast prices for liquid hydrogen for 1980-83; southern California gas prices 1980-1983; southern California electricity prices 1980-1983; projected prices for electricity and natural gas; 1983 transportation costs; and electricity and natural gas coefficients for liquified hydrogen production. These data are first used to back estimate a value for the non-energy cost component, then to forecast the price of hydrogen from 1985-2010.

The forecasting methodology involves several assumptions:

- Only electricity and natural gas prices are increasing faster than inflation. Labor, maintenance, transportation and fixed costs are assumed to remain constant in real terms. Although transportation costs may increase slightly due to rising oil or coal prices, the exact portion of transportation charges attributed to fuel costs is unknown. As transportation costs represent around 14 percent of hydrogen's delivered cost, it can be assumed that rising transportation costs will not substantially affect the delivered price of hydrogen (5-12).

- The steam reforming technology was selected as the basis for estimating the price of hydrogen. The two producers in southern California employ two different production technologies: one based on natural gas and the other using a refinery off-gas as a feedstock. The costs, technologies, and feedstock differ for the two producers. The producer employing the steam reforming technology is the marginal producer in the southern California market. The marginal producer, according to economic theory, sets the price for the industry. The other producer, with a cheaper feedstock and lower production costs, will try to just underbid or underprice the marginal producer. Thus, for the southern California market, the price is set by the producer using the steam reforming technology.

- This analysis is limited by the lack of historical data regarding the government hydrogen prices. More data would allow the calculation of error bounds on the projections, and also give an indication of the variability observed in government hydrogen prices over time. There appears to be a low price bias in the forecasts, because hydrogen prices appear to have been depressed for two of the four years for which data are available. Without additional data, it is not possible to verify which scenario reflects a "more likely" forecast for hydrogen prices in the future.

The projection of hydrogen prices for the forecast period involved the following steps:

- Step 1. An equation was used to derive the energy and non-energy cost components of hydrogen for the period 1980-1983. The equation has the form:

$$P_{hn} - P_{en}C_e - P_{an}C_a = X_{on} \qquad (5\text{-}1)$$

where

P_{hn} = price of hydrogen in year n;

P_{en} = price of electricity in year n;

C_e = kWh of electricity required to make one pound of liquid hydrogen. $C_e = 5.75$;

P_{an} = price of natural gas in year n;

n = year 1980-1983;

C_a = million Btu of natural gas required to make one pound of hydrogen. $C_a = .0885$; and

X_{on} = "other" cost component for liquid hydrogen in year n. This includes non-energy variable costs, fixed costs, and labor.

X can be calculated, as all other variables are known.

- Step 2. X_{on} is adjusted for inflation using the PPI. Average, high and low values for X are determined for the period. $X = \$0.390$/pound.

- Step 3. A mid-range price projection is formulated, using the equation:

$$P_{en}C_e + P_{an}C_a + X_o = P_{hn}$$

where

P_{en} = projected price of electricity in year n;

C_e = kWh of electricity required to make one pound of liquid hydrogen. $C_e = 5.75$;

P_{an} = projected price of natural gas in year n;

C_a = million Btu of natural gas required to make one pound of liquid hydrogen. $C_a = .0885$;

X_o = average of "other" costs from Step 2;

n = 1985-2010; and

P_{hn} = projected price of hydrogen in year n.

- Step 4. High and low scenarios are developed based on the historical high and low values for X from Step 2. The equation, as specified in Step 3, is solved again. X_{low} = \$0.185/pound. X_{high} = \$0.5842/pound.

- Step 5. The cost of transportation is calculated, based on 1983 costs. Based on a \$0.001/lb/mile estimate, the cost of transporting liquid hydrogen is \$0.213/pound. Ontario, California, the site of the steam reforming plant, is 213 road miles from VAFB.

- Step 6. The cost of transportation is added to the selling price of liquid hydrogen.

Steps 3-6 are repeated twice, using the high and low energy price forecasts in Step 3.

5.2.3 Findings

For the Mid/Avg forecast, hydrogen shows a gradual rise to a 2010 price of \$2.19/pound. The high and low price scenarios, based on mid-range energy prices, forecast prices of \$2.38 and 1.98/pound. When energy prices are also varied from low to high, hydrogen prices range from \$1.73 to 2.60 /pound. The Mid/Avg forecast is at the midpoint of an \$0.87/pound price difference between the extreme prices. Table 5-9 lists the prices for the five scenarios.

TABLE 5-9. LIQUID HYDROGEN PRICE SCENARIOS
(in 1983 dollars, $/pound)

Scenario Number	Scenario Name	1985	1990	1995	2000	2010
1	Mid/Avg	1.67	1.68	1.86	2.02	2.19
2	Mid/Low	1.46	1.46	1.65	1.81	1.98
3	Mid/High	1.86	1.87	2.05	2.21	2.38
4	Low/Low	1.43	1.43	--	1.69	1.73
5	High/High	1.88	1.92	--	2.33	2.60

The five scenarios in Table 5-9 are explained further in Table 5-10.

TABLE 5-10. HYDROGEN SCENARIO DESCRIPTION

Scenario Number	Scenario Name	Energy and Non-Energy Cost Components
1	Mid/Avg	Mid-range energy prices and average non-energy costs
2	Mid/Low	Mid-range energy prices and low non-energy costs
3	Mid/High	Mid-range energy prices and high non-energy costs
4	Low/Low	Low energy prices and low non-energy costs
5	High/High	High energy prices and high non-energy costs

Commercial liquid hydrogen price projections were similarly developed. Table 5-11 lists commercial prices for Scenario 1, which is based on mid-range electricity price estimates and an average "other" cost component.

TABLE 5-11. COMMERCIAL LIQUID HYDROGEN PRICE PROJECTIONS[1]
(in 1983 dollars, $/pound)

	Year/Price ($/pound)			
Year	1985	1990	2000	2010
Price	2.88	2.89	3.23	3.41

[1] Includes transportation.

The average non-energy cost component for 1977-83 is $1.61/pound. This is based on price data from Air Products and Linde. This compares to the $0.39/pound average "other" cost component for government-purchased hydrogen. Since 1980, the "other" or non-energy cost component for commercial hydrogen has been rising steadily, from $1.37 to 1.93/pound, excluding transportation. Thus, the "other" component for 1983 is higher than the overall average for the period 1977-83.

5.3 LIQUID OXYGEN AND LIQUID NITROGEN PRICE FORECASTS

This section discusses liquid nitrogen and oxygen markets and production, describes the price forecasting methodology, and presents commodity price projections to the year 2010.

5.3.1 Background

5.3.1.1 Producers--Liquid oxygen and nitrogen are produced by numerous air separation plants across the United States. In 1978, approximately 180 plants produced oxygen in 40 states. Nitrogen production plants numbered over 300. Despite the large number of plants, the industry is dominated by eight major companies: Linde Division-Union Carbide Corp.; Airco, Inc.; Air Products and Chemicals, Inc.; Chemetron Corp.; Liquid Air Inc.; Big Three Industries, Inc.; Liquid Carbonic Corp.; and Burdox, Inc. (5-15). In some cases these companies are able to exert price pressure due to their market share. In 1982, Linde Division, with 50 percent of nitrogen production capacity, was able to prevent competitors from increasing the price of nitrogen by $0.04/100 cubic feet (5-9).

The economics of industrial gas production are changing. Overcapacity has become a concern in the industry, since it is estimated that the industry increased its capacity by 25 percent in 1977 (5-15). Overcapacity is expected to decrease profit margins for oxygen and, to a lesser extent, nitrogen producers in 1983 (5-16). Another concern to industrial gas producers is the rising price of power. Increased power costs could raise the breakeven point of plants above the present level of 70 percent capacity. This will occur if price increases for oxygen and nitrogen do not keep up with power price increases (5-15). In the long term, according to industry staff, the price of industrial gases has to follow the price of power (Bill Sandig, Airco Industrial Gases, personal communication).

5.3.1.2 Markets and Uses--Liquid oxygen prices fell in 1983, despite an increase in electricity prices. Prices for nitrogen, oxygen and electricity for 1967-1983 are illustrated in Figure 5-8. The oxygen price reduction is

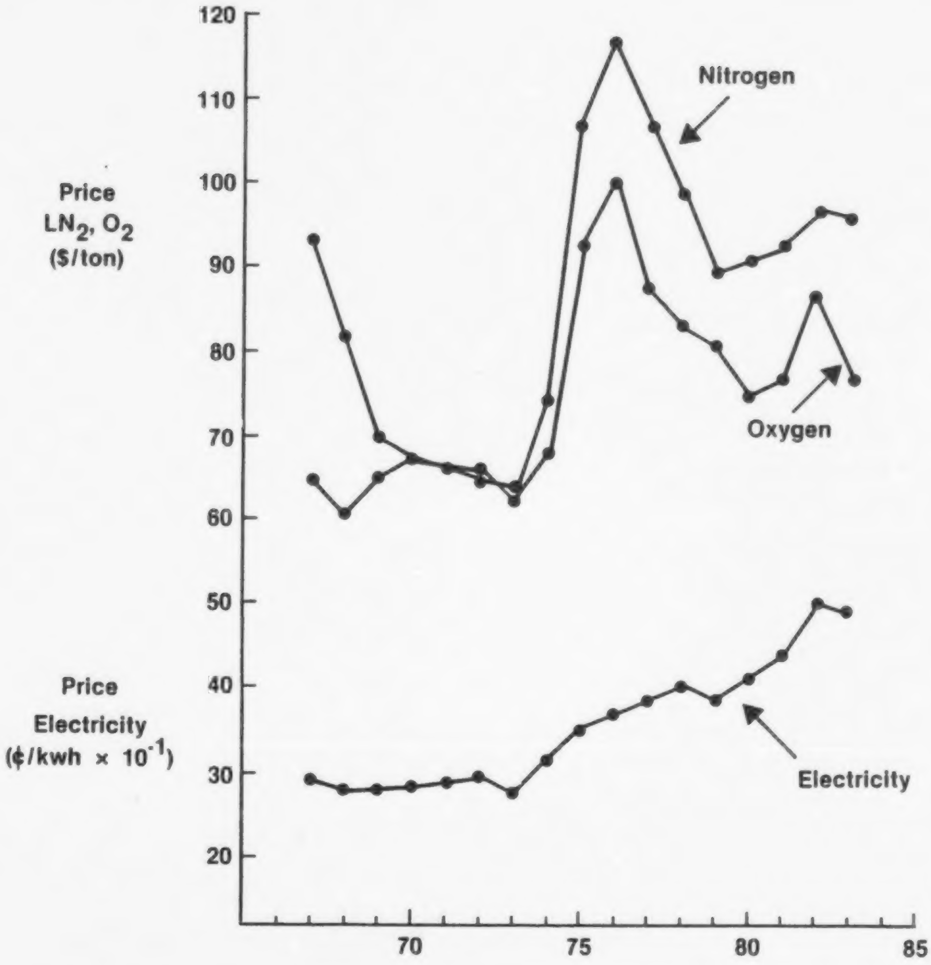


Figure 5-8. Oxygen, nitrogen, and electricity prices 1967-1983 (1983 $)

the result of the decreased demand in the early 1980s. Production data, listed in Table 5-12, show a 50 percent drop in the demand for oxygen from 1981 to 1983. In 1983, oxygen production was at its 1972 level. In contrast, the demand for nitrogen continued to grow from 1980 to 1983. The uses of nitrogen are less sensitive to economic fluctuations (5-16).

About 35 percent of oxygen is produced as a liquid and is supplied to the chemical, metal working, metal production, medical and waste treatment industries (5-17). The major consumer of all oxygen produced is the iron and steel industry, which uses oxygen in blast furnaces and to condition and cut steel (5-15). Since the iron and steel industry consumes over 50 percent of the oxygen produced, the decrease in oxygen demand from 1980 to 1983 is explained by the iron and steel industry's poor performance during that period (5-8).

Twenty-two percent of the nitrogen produced is used as a liquid to freeze food. Liquid nitrogen is also used to cryogenically prepare material for grinding, pulverize heat sensitive materials, deflash molded plastics and recovery oil (5-15, 5-18, and 5-19). The wide variety of uses for nitrogen provides more price stability than is found in the oxygen market.

VAFB purchases oxygen and nitrogen commodities from the Air Force Logistics Center (AFLC), which charges all buyers a standard price. The standard price is based on the average costs incurred by AFLC for the purchase and delivery of industrial gases to all military users.

5.3.2 Methodology

The price of nitrogen and oxygen are forecasted by allocating the prices of the commodities into electricity and non-electricity cost components. Non-electricity costs include non-fuel variable costs, labor, maintenance, transportation, and fixed costs. Non-electricity costs are assumed to remain con-

TABLE 5-12. NITROGEN AND OXYGEN PRODUCTION
(million cubic feet)

	Jan 1971	Jan 1972	Jan 1973	Jan 1974	Jan 1975	Jan 1976	Jan 1977	Jan 1978	Jan 1979	Jan 1980	Jan 1981	Jan 1982	Jan 1983
Nitrogen													
Gas													
Pipeline Shipment	7,907	9,005	11,246	12,432	12,687	13,412	17,012	19,145	22,447	26,581	26,795	25,818	28,028
In Plant Consumption	1,242	1,110	1,594	1,779	1,773	1,844			5,144[2]	3,271	3,295	3,068	1,349
Liquid													
Bulk Shipment	417	466	342	323	790	822	674	366	[1]	518	797	880	672
In Plant Consumption	109	95	206	280		286			[2]	275	282	380	431
Liquid and Gas													
Cylinder and Bulk	3,919	4,442	4,602	5,673	5,805	5,751	6,890	7,301	8,470[1]	8,117	8,978	10,512	10,233
In Plant Consumption							2,494	4,530					
TOTAL	13,594	15,118	17,990	20,487	21,055	22,115	27,070	31,342	36,061	38,744	40,146	20,658	40,713
Oxygen													
Gas													
Pipeline Shipment	19,654	19,223	21,494	23,431	23,413	20,500	20,463	22,967	26,426	29,361	24,623	22,937	18,957
Liquid													
Bulk Shipment	995	656	802	795	820	622	425	522	[3]	[3]	6,143	5,646	5,518
Liquid and Gas													
Cylinder and Bulk	3,149	3,289	3,799	4,366	4,240	4,186	4,833	5,046	6,013[3]	5,490[3]			
In Plant Consumption	4,724	4,284	5,043	4,326	3,692	4,533	4,853	3,703	4,194	4,504	4,909	3,244	2,991
TOTAL	28,522	27,452	31,138	32,918	32,165	29,841	30,574	32,238	36,633	39,355	35,675	31,827	27,466

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[1] Data for liquid nitrogen produced for bulk delivery shipment are combined with liquid and gas nitrogen produced for cylinder and bulk delivery shipment to avoid disclosure of individual company's figures.

[2] Data for gas nitrogen for in-plant consumption are combined with liquid nitrogen in-plant consumption in order to avoid disclosing figures for individual companies.

[3] Liquid oxygen for bulk delivery shipment is included in liquid and gas oxygen produced for cylinder and bulk delivery shipment to avoid disclosing individual company's figures.

stant in real terms, whereas future electricity costs are escalated by the electricity price increases discussed in Section 5.1.2.

An average value for non-electricity costs is determined by back estimating the price of electricity for 1973-1983. Data for back estimating and forecasting include: 1) the standard prices of liquid nitrogen and oxygen 1973-1983; 2) the national average price of electricity for the industrial sector for 1973-1983; 3) projected prices for electricity 1983-2010; and 4) electricity coefficients for liquified nitrogen and oxygen production.

The methodology involves the following assumptions:

- Only electricity prices increase at a rate faster than inflation. Other energy-related costs, such as transportation, constitute 13-16 percent of the current commodity price for VAFB. According to AFLC's figures, the cost of delivery to VAFB is 0.076 $/ton-mile. Based on available data on VAFB delivery costs, transportation does not appear to be a significant cost.
- Variability in costs and profits experienced from 1973 to 1983 is representative. Pre-1973 data were not included because very different factors dominated the industrial gas market before that date. Before 1972, the price of electricity was falling in real terms. Also, in the 1960s, technological change in the steel industry opened up an enormous market for pipeline gas, which resulted in a dramatic oxygen price reduction. Nitrogen prices also fell since nitrogen was a co-product (5-20).
- The technology for oxygen and nitrogen production will not become more efficient during the forecast period.

The following steps were used to forecast the prices of liquid nitrogen and oxygen:

- Step 1. An equation was used to back estimate the values for non-fuel variable and fixed costs for the period 1973-1983. It has the form:

$$P_{gn} - (P_{en})(C_g) = X_{gn}$$

where

P_{gn} = standard price of g, liquified nitrogen or oxygen, in year n;

g = liquified oxygen or nitrogen;

n = year 1973-1983;

P_{en} = national average price of industrial sector electricity in year n;

C_g = kWh of electricity required to produce 1 pound of liquified gas g; $C_{nitrogen} = 0.28$ and $C_{oxygen} = 0.38$; and

X_{gn} = non-fuel variable costs, fixed costs, labor and transportation for liquified gas g in year n.

X_{gn} is calculated as the residual of the known variables.

- Step 2. X_{gn} is adjusted for inflation, using the PPI for all commodities. An average, high and low value for non-electricity costs, X_{gn}, is determined from the historical data. The lowest value for X_{oxygen} was \$0.0196/lb. The highest was \$0.036/lb and the average was \$0.0252/lb. For nitrogen, the extremes are \$0.026 and 0.048/lb, with an average of \$0.0358/lb.

- Step 3. A mid-range price projection for both gases is formulated using the equation:

$$(P_{en}) (C_g) + X_g = P_{gn}$$

where

P_{en} = price of electricity in year n; national forecasts are presented in Section 5.1.2;

n = year 1985-2010;

g = nitrogen or oxygen;

X_g = average value for non-fuel variable costs, fixed costs, labor and transportation, from Step 2;

C_g = kWh of electricity required to produce 1 pound of liquified gas g; $C_{nitrogen} = 0.28$ and $C_{oxygen} = 0.38$; and

P_{gn} = price of liquified gas g in year n.

- Step 4. High and low scenarios are developed based on the historical high and low values for X_g, determined in Step 2. The equation as specified in Step 3 is solved again, varying the range of X_g.

- Step 5. Calculate the standard deviation of the non-electricity costs, X_{gn}, for each liquified gas.

5.3.3 Findings

Price increases for liquid nitrogen and oxygen are projected to track price increases for electricity. Upper and lower boundaries are also constructed for each commodity, based on the mid-range electricity price forecast. The upper and lower boundaries are the result of the variability observed in the standard prices paid by VAFB, minus the electricity costs. Table 5-13 lists prices for the high, low and mid-range scenarios for 1985-2010.

The standard price for liquid oxygen is forecasted to reach $101/ton in 2010. Figure 5-9 illustrates the prices of electricity and oxygen for 1973-2010. All prices are real (adjusted for inflation). As Figure 5-9 shows, currently the price of oxygen is below its real average price of $81/ton (1983 dollars). A below average price is not expected to continue in the long run, as price rises for electricity indicate increasing costs to the producer. Given an economic recovery, the real price is expected to bounce back and continue a real upward climb. There are indications this is already occurring, as demand is rising and producers are discontinuing commercial discounts (5-21).

Nitrogen prices have not experienced a sharp downturn. Instead, as Figure 5-9 shows, nitrogen has followed electricity closely since 1979. The price of nitrogen is forecasted to continue upward to $109/ton in 2010.

Prices could be expected to cluster around the mid-range price or to equal the mid-range price when averaged over several years. Too low a price will drive marginal producers out of business and too high a price will stimulate supply. Either of these actions would lead to a return to a mid-range price in the long run. Thus, the boundaries are high and low prices which might be encountered in the short run. In the long run, prices are forecasted to equal the mid-range projection in Table 5-13.

In order to assess the variability in the non-electricity cost data from 1973-1983, the standard deviations for non-electricity costs have been calculated for nitrogen and oxygen separately. When added to the projected electricity cost for the forecast period, the standard deviation boundaries provide an indication of the likelihood of future prices occurring within a

TABLE 5-13. LIQUID NITROGEN AND OXYGEN PRICE PROJECTIONS[1] (in 1983 dollars)

	Year/Price ($/ton)					
	1983[2]	1985	1990	1995	2000	2010
Oxygen						
Mid-range	76.00	88.00	91.00	93.00	96.00	101.00
Low		77.00	79.00	81.00	83.00	89.00
High		111.00	113.00	115.00	117.00	123.00
Nitrogen						
Mid-range	96.00	100.00	101.00	103.00	105.00	109.00
Low		80.00	82.00	83.00	85.00	89.00
High		124.00	126.00	127.00	129.00	133.00

[1] Based on mid-range electricity price forecasts.
[2] July 1983 price, AFLC price list.

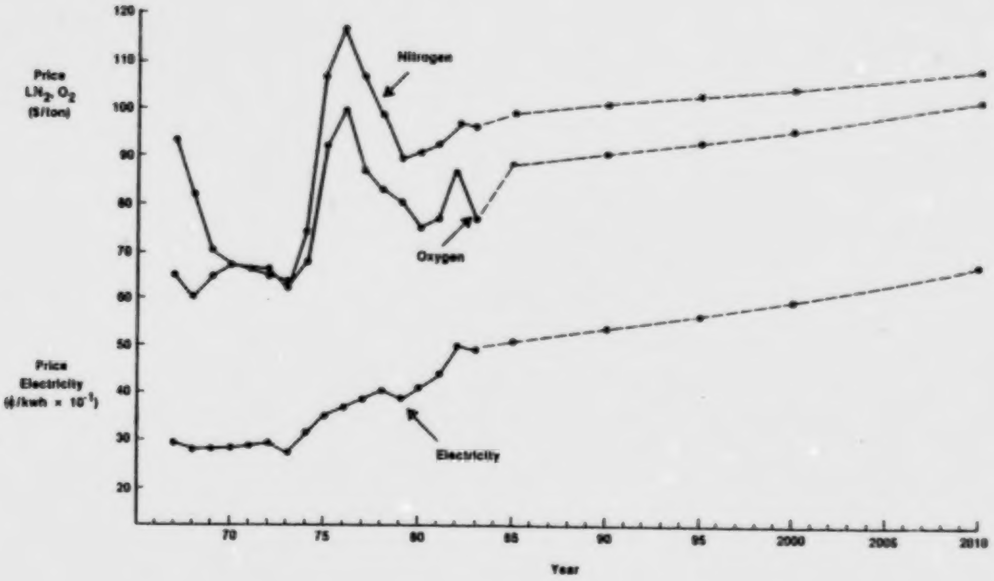

Figure 5-9. Oxygen, nitrogen and electricity prices 1967-2010 (1983 $)

specified range, given a mid-range price for electricity. The non-electricity cost standard deviation was used in the equation:

$$(\text{Projected price of electricity}_n)\ (\text{Electricity coefficient}_g) + (\text{Average non-electricity cost}_g \pm 1\ \text{standard deviation}_g) = \text{price of commodity}_n$$

where

n = year and

g = liquid nitrogen or oxygen.

The standard deviation for oxygen's non-electricity cost component is \$0.52/lb. For nitrogen, the standard deviation is \$0.55/lb.

The standard deviation-derived price bounds for the two commodities are displayed in Figure 5-10 and 5-11. These bounds can be compared to the upper and lower boundaries forecasted for the commodity prices. It would be expected that 66 percent of the prices in the future would lie within the ±1 standard deviation lines in Figure 5-10 and 5-11, given the mid-range forecasted price for electricity.

The standard deviation-derived boundaries for nitrogen indicate that a price near either the upper or lower bounds is equally likely.

Varying the price of electricity introduces additional uncertainty into the commodity price projections. Figures 5-12 and 5-13 show 5 scenarios of the commodity price projections. The scenarios are based on the national low, middle and high electricity price forecasts from Section 5.1.2 and low, average and high non-electricity cost components. The scenarios in Figures 5-12 and 5-13 and Tables 5-14 and 5-15 correspond to the scenarios listed in Table 5-16.

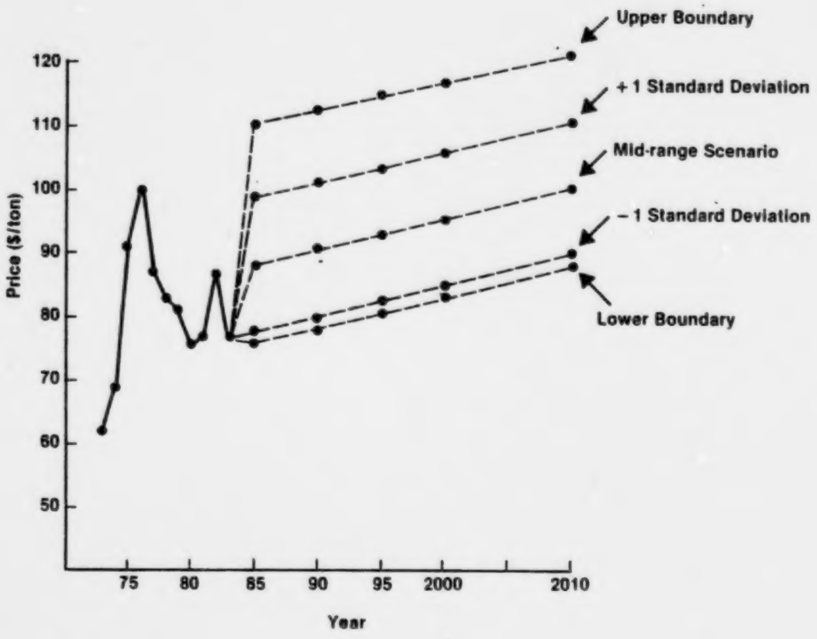

Figure 5-10. Liquid oxygen price scenarios (based on mid-range elec. forecast)

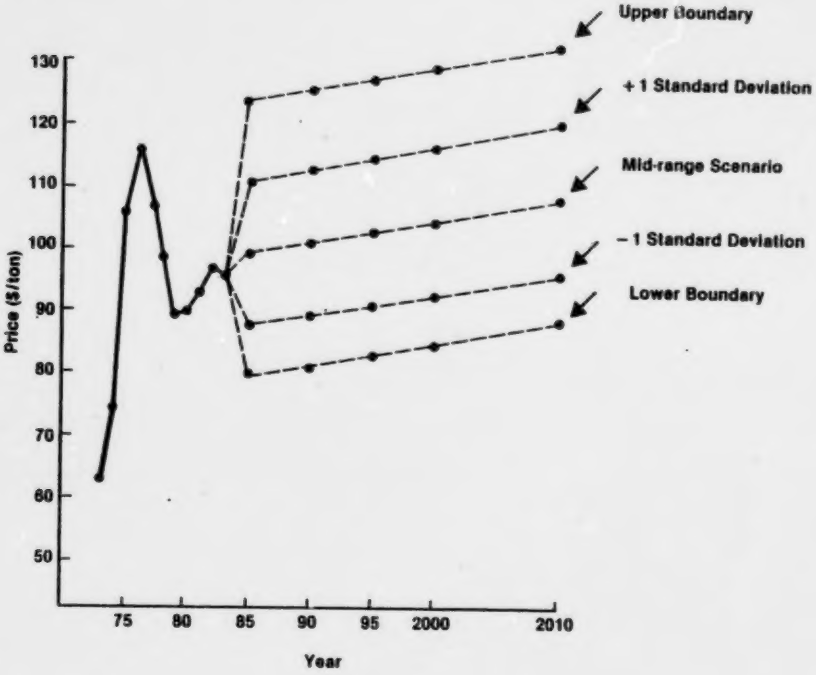

Figure 5-11. Liquid nitrogen price scenarios (based on mid-range elec. forecast)

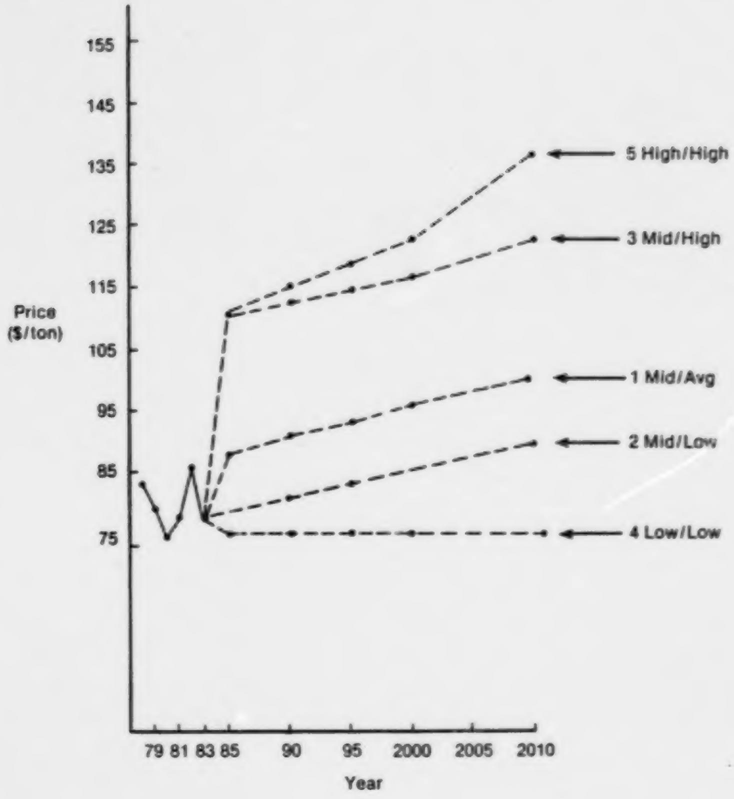

Figure 5-12. Oxygen price scenarios (1983 dollars)

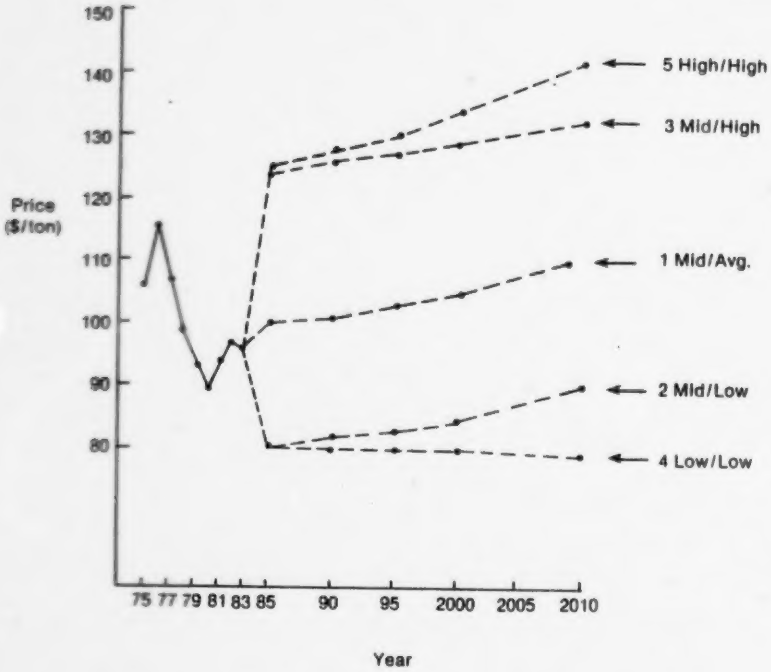

Figure 5-13. Nitrogen price scenarios (1983 dollars)

TABLE 5-14. OXYGEN PRICE SCENARIOS
(in 1983 dollars)

Scenario Number	Variable		Year/Price ($/ton)				
	Price of Electricity	Non-Elec Costs	1985	1990	1995	2000	2010
1	Mid-range	Average	88.00	91.00	93.00	96.00	101.00
2	Mid-range	Low	77.00	79.00	81.00	83.00	89.00
3	Mid-range	High	111.00	113.00	115.00	117.00	123.00
4	Low	Low	76.00	76.00	76.00	76.00	75.00
5	High	High	111.00	115.00	119.00	124.00	135.00

TABLE 5-15. NITROGEN PRICE SCENARIOS
(in 1983 dollars)

Scenario Number	Variable		Year/Price ($/ton)				
	Price of Electricity	Non-Elec Costs	1985	1990	1995	2000	2010
1	Mid-range	Average	100.00	101.00	103.00	105.00	109.00
2	Mid-range	Low	80.00	82.00	83.00	85.00	89.00
3	Mid-range	High	124.00	126.00	127.00	129.00	133.00
4	Low-range	Low	80.00	80.00	80.00	80.00	79.00
5	High-range	High	125.00	128.00	131.00	134.00	142.00

TABLE 5-16. NITROGEN AND OXYGEN SCENARIO DESCRIPTIONS

Scenario Number	Name	Electricity and Non-Electricity Cost Combinations
1	Mid/Average	Mid-range electricity prices and Average non-electricity costs.
2	Mid/Low	Mid-range electricity prices and High non-electricity costs.
3	Mid/High	Mid-range electricity prices and High non-electricity costs.
4	Low/Low	Low electricity prices and Low non-electricity costs.
5	High/High	High electricity prices and High non-electricity costs.

The scenarios illustrate the wide range in the possible prices of nitrogen and oxygen. The price of oxygen in 2010 varies from 75 $/ton to 135 $/ton. The price of nitrogen ranges from 79 $/ton to 142 $/ton. For both commodities, the extreme prices are the result of combining the low electricity and low non-electricity cost components or the high electricity and high non-electricity cost components.

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Section 6

COMMODITY TRANSPORTATION ISSUES

An alternative to the production of commodities is the continued purchase from vendors. This section examines transportation costs and safety considerations for rail and truck transportation of commodities to VAFB. A review of monetary and "social" costs of the continued transportation from the vendor's production sites also is provided.

6.1 COMPARISON OF TRUCK AND RAIL COSTS

Table 6-1 summarizes truck transportation cost estimates from several sources. Historical costs for transporting liquid hydrogen appear more consistent than for the transportation of oxygen and nitrogen. However, the transportation costs in the new hydrogen contract are substantially reduced, representing the impact of a very competitive market due to oversupply on the West Coast.

Data on fixed charges versus per mile charges were not available, but an estimate of driver labor was provided by Jack B. Kelly Company (personal communication with Bill Oster). Driver rates are $30 to $35 per hour. Loading and unloading times, each 2 hours, are included in the per mile charges. Any additional time required would add to the transportation cost.

TABLE 6-1. COST OF COMMODITY TRANSPORTATION BY TRUCK

Source	Commodity	Quoted Price	Cost
Bill Oster at Jack B. Kelley Company	LH_2	\$1,081.20/truck load from Long Beach to VAFB (6000# min, 7000# max)(171 miles)	\$0.00091 - \$0.0011/lb
	LO_2 LN_2	\$671.46/truck load (42,000#)	\$0.19/ton-mile
Skip Carr, AFLC	LH_2	\$0.05/50 lb-miles	\$0.001/lb-mile
	LO_2 LN_2	\$1.50/loaded mile/tanker (20 ton capacity)	\$0.075/ton-mile
Frank Lively, MSFC	LH_2	\$2.16/truck mile for 1268 mile trip from New Orleans to KSC (7000#/truck)	\$0.00031/lb-mile
David Hoffman, KSC	LH_2	\$33,600 for 12 tank trucks 10,000 gal/trailer actually delivered New Orleans to KSC (634 miles)	\$1.52/ton-mile
D. W. Thurman, MSFC	LH_2	\$.0502/lb H_2 average cost of delivering 7,133,080 lb excluding demurrage, etc., from Long Beach to Santa Susanna, 1980-1982 (50 miles)	\$0.001/lb-mile
	LH_2	\$.057/lb H_2 average cost of delivering 5,421,730 lb excluding demurrage, etc., from Long Beach to Santa Susanna, 1982-September, 1983 (50 miles)	\$0.0011/lb-mile
Frank Lively, MSFC	LH_2	\$.0461/lb H_2 contract cost for delivery between Ontario and Santa Susanna, 1984-1985 (90 mi)	\$0.00051/lb-mile
	LH_2	\$.0801/lb H_2 contract cost for delivery between Ontario and VAFB (213 miles), 1984-1985.	\$0.00038/lb-mile

Rail transportation rates have been estimated for two routes, and are shown in Table 6-2.

TABLE 6-2. COST OF COMMODITY TRANSPORTATION BY RAIL

Source	Commodity	Quoted Price	Cost
Southern Pacific	LO_2 LN_2	\$1.59/cwt for Long Beach to San Jose (430 miles), 160,000 lb minimum	\$0.074/ton-mile
David Hoffman, KSC	LH_2	\$15,561 for 4 carloads, 30,000 to 34,400 gallons delivered New Orleans to KSC (710 miles)	\$0.0003/lb-mile

6.2 COST AND AVAILABILITY OF RAIL CARS

At the present time, the federal government owns four LH_2 rail cars, each of which has a total volume of 36,100 gallons. Each rail car can be filled to 34,400 gallons and is assumed to deliver 30,000 gallons to KSC after the trip from New Orleans. Each of the cars is 84 feet long and has an empty weight of 171,800 pounds. The cars cost \$350,000 to build originally, and replacement cost has been estimated at \$750,000 (personal communication with David Hoffman, KSC).

In addition, Linde owns twenty LH_2 rail cars, each with 28,300 gallons of usable capacity. Linde did not provide information on the availability or cost of use of these cars (personal communication with David Hoffman, KSC).

According to Southern Pacific, cryogenic tank cars of 16,000 gallon capacity (probably LO_2 or LN_2) lease for around $1,000/month, plus $4,000 make-ready fees (personal communication with Jill Rossi, Southern Pacific).

6.3 SAFETY OF TRUCK VS. RAIL TRANSPORT

Social costs should also be considered in comparing truck versus rail transportation. Accidents represent the most significant social cost likely to be associated with commodity transportation. The USAF recently participated in a fuels transportation study by civilian groups in areas adjacent to VAFB and has recommended that highway routes having the lowest accident expectancy be selected for fuels transportation (6-1).

Accident likelihood is an important safety consideration for fuels transportation. Data showing rail transportation is substantially safer than highway delivery are presented in Tables 6-3 and 6-4.

TABLE 6-3. HAZARDOUS MATERIAL TRANSPORTATION STATICTICS, 1971-1977 (6-10)

	Rail	Truck
Percent of Hazardous Material Transported	40	60
Percent of Hazardous Material Accidents	9	91
Percent of Fatalities	20	80
Percent of Injuries	25	75

TABLE 6-4. HAZARDOUS MATERIALS TRANSPORTATION STATISTICS, 1980-1982 (Materials Transportation Bureau data, personal communication with D. Hoffman, KSC)

	1980		1981		1982	
Accidents						
Air	233		160		93	
Highway for hire	14,042	14,484	7,441	7,704	5,081	5,383
Highway private	442		263		302	
Rail	1,327		1,131		783	
Water	42		7		9	
Freight forwarder	1		3		6	
Others	28		58		3	
Total Accidents	16,115		9,063		6,277	
Fatalities						
Air	0		0		0	
Highway for hire	13	17	24	27	11	12
Highway private	4		3		1	
Rail	2		0		0	
Water	0		0		0	
Freight forwarder	0		0		0	
Others	0		0		0	
Total Fatalities	19		27		12	
Injuries						
Air	8		7		9	
Highway for hire	425	478	368	397	69	86
Highway private	53		29		17	
Rail	129		221		35	
Water	1		0		1	
Freight forwarder	1		0		0	
Others	2		18		0	
Total Injuries	619		643		122	

In 1979, an analysis was carried out by Aerospace Corporation on the risk of accident associated with hydrazine-based liquid rocket propellant (6-2). Using their approach, accident risk associated with commodity transportation can be estimated.

A total of 48 trips per launch are required to transport LH_2 from Ontario to VAFB (6-1). The distance per trip is 213 miles, for a total distance of 10,224 miles (one-way). A total of 50 trips per launch are required to transport LO_2 from Los Angeles to VAFB (6-1). This trip distance is 171 miles, for a total distance of 8,550 miles. Table 6-5 gives the predicted statistical accident rate and a predicted release of cargo rate based upon accidents with liquified petroleum.

Based upon the results presented in Table 6-5, an accident involving truck transportation of cryogenics statistically would be likely to occur once every 24 to 55 launches. A truck accident in which cryogenic liquids were released statistically would be likely to occur once every 37 to 83 launches.

Transportation by rail would have a lower risk of accident, as shown in Table 6-6. An accident in which cryogenic liquids were released statistically would be likely to occur once every 81 to 100 launches.

At the present time, only helium is scheduled to be transported by rail, and only helium has rail unloading facilities available at SLC-6. Hydrogen unloading facilities would require additional plumbing and a rail siding within 200 feet of the hydrogen dewer.

The rail industry, with encouragement from DOT, is in the process of upgrading cars used for hazardous material transportation by adding heavier end caps and using shelf couplers. Both of these improvements are intended to

TABLE 6-5. PREDICTED TRUCK CRYOGENIC ACCIDENT RATE

	Trend	Average
Truck accidents per million vehicle miles (6-2)	0.95	2.24
Loaded truck miles per launch: Hydrogen	10,224	
Oxygen	8,550	
Predicted accidents per launch	0.018	0.042
Predicted release of cargo rate per accident (6-3)	0.64	0.64
Predicted release of cargo accident rate per launch	0.012	0.027

TABLE 6-6. PREDICTED RAIL CRYOGENIC ACCIDENT RATE

	Trend	Average
Rail car accidents per million car miles (6-2)	3.70	2.99
Loaded rail miles per launch: Hydrogen	3290	
Oxygen	1907	
Predicted accidents per launch	0.019	0.015
Predicted release of cargo rate per accident (6-3)	0.64	0.64
Predicted release of cargo accident rate per launch	.012	.010

reduce the "spearing" of cars carrying hazardous materials by adjacent cars. Liquid hydrogen cars already have these features.

For rail transportation, measures would need to be taken to assure that rail crews were adequately trained in liquid hydrogen handling and emergency response procedures.

6.4 PUBLIC OPINION CONSIDERATIONS

There has been local concern expressed in Southern California regarding transport of rocket fuels to VAFB. The Lompoc mayor requested that fuel not be transported through the city (personal communication with Lloyd Edsel), and General Watkins concurred with that request. A routing policy was established in February, 1983, after consultation with local community officials. An article appeared in the Los Angeles Times on April 28, 1983 (6-4), calling attention to the transportation issue and reporting on legislation introduced into the California Senate restricting the routes over which rocket fuels may be transported.

The relatively low launch rate forecast and the low accident probability estimated above will probably reduce public concern for the VAFB launches. The continued activity of the Community Impact Committee will also assist in dealing with public concerns.

6.5 REFERENCES

6-1 Letter regarding Routing of Missile and Space Programs Propellants from General Jack L. Watkins, 1 February 1983.

6-2 Sherwin Lewis, "Storable Liquid Rocket Transportation Risk Analysis", Second Conference on Environmental Chemistry of Hydrazine, 15 February 1979.

6-3 Department of Transportation Hazardous Materials Information System, printout on Hazardous Materials Incidents Involving Liquid Petroleum Gas, 1978 to September 30, 1983, 40 pp.

6-4 T. S. McGarry, "Highly Volatile, Toxic Fuels to Travel Roads", Los Angeles Times, April 28, 1983.

Section 7

TECHNICAL AND ECONOMIC CHARACTERIZATION OF CANDIDATE SYSTEMS

Candidate systems for producing electrical power and/or commodities at VAFB are not equally suitable for supplying VAFB needs; the candidate systems inherently differ in a number of areas. In this section, the candidate systems are characterized in the following areas: development status (as a measure of technical risk), conversion efficiency, environmental impacts, reliability, supply vulnerability, and economics. The basic characterization data developed in this section are then used in Section 8 to evaluate the candidate systems and to identify the most attractive systems for use at VAFB.

Section 7 is organized into three subsections. Section 7.1 summarily identifies the candidate production systems. Section 7.2 provides technical characterization data on the candidate production systems while Section 7.3 develops economics characterization data. Additional technical characterization is provided in Appendix A, and complete economics characterization is provided in Appendix B.

7.1 IDENTIFICATION OF CANDIDATE PRODUCTION SYSTEMS

The electricity production systems analyzed in this report are identified in Table 7-1. Systems considered for commodities production are listed in Table 7-2. And systems considered for production of both commodities and electricity are identified in Table 7-3. Concepts which were initially identified but subsequently excluded from technical and economic analysis were identified in Section 1.

Descriptions of the basic technologies used in these systems are presented in Appendix A. The more complex production systems are also

TABLE 7-1. ELECTRICITY PRODUCTION SYSTEMS SELECTED FOR STUDY

Production Technology	Fuel	Critical Launch Demands (CLD) Only	CLD and Continuous Loads	Continuous Loads Only
Boiler/Steam Turbine (Rankine cycle)	● Natural Gas		✓	✓
	● No. 2 Fuel Oil		✓	✓
	● No. 6 Fuel Oil		✓	✓
	● Coal			
	- AFBC[1]		✓	✓
	- Stoker or PC[2]		✓	✓
Gas Turbine (Brayton cycle)	● Natural Gas	✓	✓	✓
	● No. 2 Fuel Oil[3]	✓	✓	✓
Combined Cycle Turbines	● Natural Gas		✓	✓
	● No. 2 Fuel Oil		✓	✓
	● Fuel Gas			
	- via coal gasification		✓	✓
	- via partial oxidation of No. 6 fuel oil[4]		✓	✓
Diesel Engine (Otto cycle)	● No. 2 Fuel Oil	✓	✓	✓
Fuel Cell[5]	● Fuel Gas			
	- via steam reforming of natural gas		✓	✓
	- via partial oxidation of No. 6 fuel oil[4]		✓	✓
	- via coal gasification		✓	✓
Wind Turbines	--			✓
Solar Central Receiver (Power Tower)	--			✓

(continued)

TABLE 7-1. (continued)

Production Technology	Fuel	Critical Launch Demands (CLD) Only	CLD and Continuous Loads	Continuous Loads Only
Solar Photovoltaics	--			✓
Pumped Hydro Storage (PG&E Grid)	● Electricity/Water	✓		

---

[1] Atmospheric Fluid-bed combustion.

[2] For the turbine sizes considered in this study (10 to 20 MW), stoker coal fired boilers are more commonly used than pulverized coal fired boilers. Larger turbines typically use pulverized coal fired boilers.

[3] Use of No. 6 fuel oil may not be feasible in gas turbines due to its high ash and vanadium contents. Use of fuel gases generated from coal or No. 6 oil is impractical due to the inherently low efficiency of simple gas turbines and fuel gas generation. Thus, these systems were not studied.

[4] Partial oxidation of No. 2 fuel oil is less economic than oxidation of No. 6 fuel oil due to the higher cost of No. 2 fuel oil; thus, No. 2 fuel oil systems were not studied.

[5] Small steam turbine/generator systems are included to make use of by-product steam.

TABLE 7-2. COMMODITIES PRODUCTION SYSTEMS SELECTED FOR STUDY

Production Technology	Fuel/Feedstock	Products
Steam Reforming[1]	Natural Gas	• Liquid Hydrogen
Partial Oxidation[1]	No. 6 Fuel Oil[2]	• Liquid Hydrogen • Gaseous Nitrogen[3]
Gasification[1]	Coal	• Liquid Hydrogen • Gaseous Nitrogen[3]
Air Separation	Electricity, Air	• Liquid Nitrogen • Liquid Oxygen • Gaseous Nitrogen
Electrolysis	Electricity, Water	• Liquid Hydrogen • Liquid Oxygen
Coal Gasification/ Air Separation[4]	Coal	• Liquid Hydrogen • Gaseous Nitrogen • Liquid Nitrogen • Liquid Oxygen

[1] These are principal production technologies; ancillary but required technologies include hydrogen liquefaction, and steam turbines. The steam turbines are used to generate a portion of the plant power requirements from by-product steam.

[2] Partial oxidation of No. 2 fuel oil is less economic than oxidation of No. 6 fuel oil due to the higher cost of No. 2 fuel oil; thus, No. 2 fuel oil systems were not studied.

[3] Coal gasification and partial oxidation plants normally use air separation to produce gaseous oxygen which is used in gasification or oxidation. The remaining separated gaseous nitrogen is then available for blanketing and other uses.

[4] Coal gasification plants normally use air separation to produce gaseous oxygen which is used in gasification. The remaining separated nitrogen is then available for blanketing and other uses. In this system concept, the air separation unit is oversized and redesigned to produce the additional required quantities of liquid nitrogen and liquid oxygen.

TABLE 7-3. COMMODITIES AND ELECTRICITY PRODUCTION SYSTEMS SELECTED FOR STUDY

Production Technologies	Products
Wind Turbines/Electrolysis	• Electricity • Liquid Hydrogen • Liquid Oxygen
Wind Turbines/Air Separation	• Electricity • Liquid Nitrogen • Liquid Oxygen • Gaseous Nitrogen
Coal Gasification/Combined Cycle Turbine[1]	• Electricity • Liquid Hydrogen • Gaseous Nitrogen

---

[1] Conceptually similar to NASA's KSC polygeneration concept.

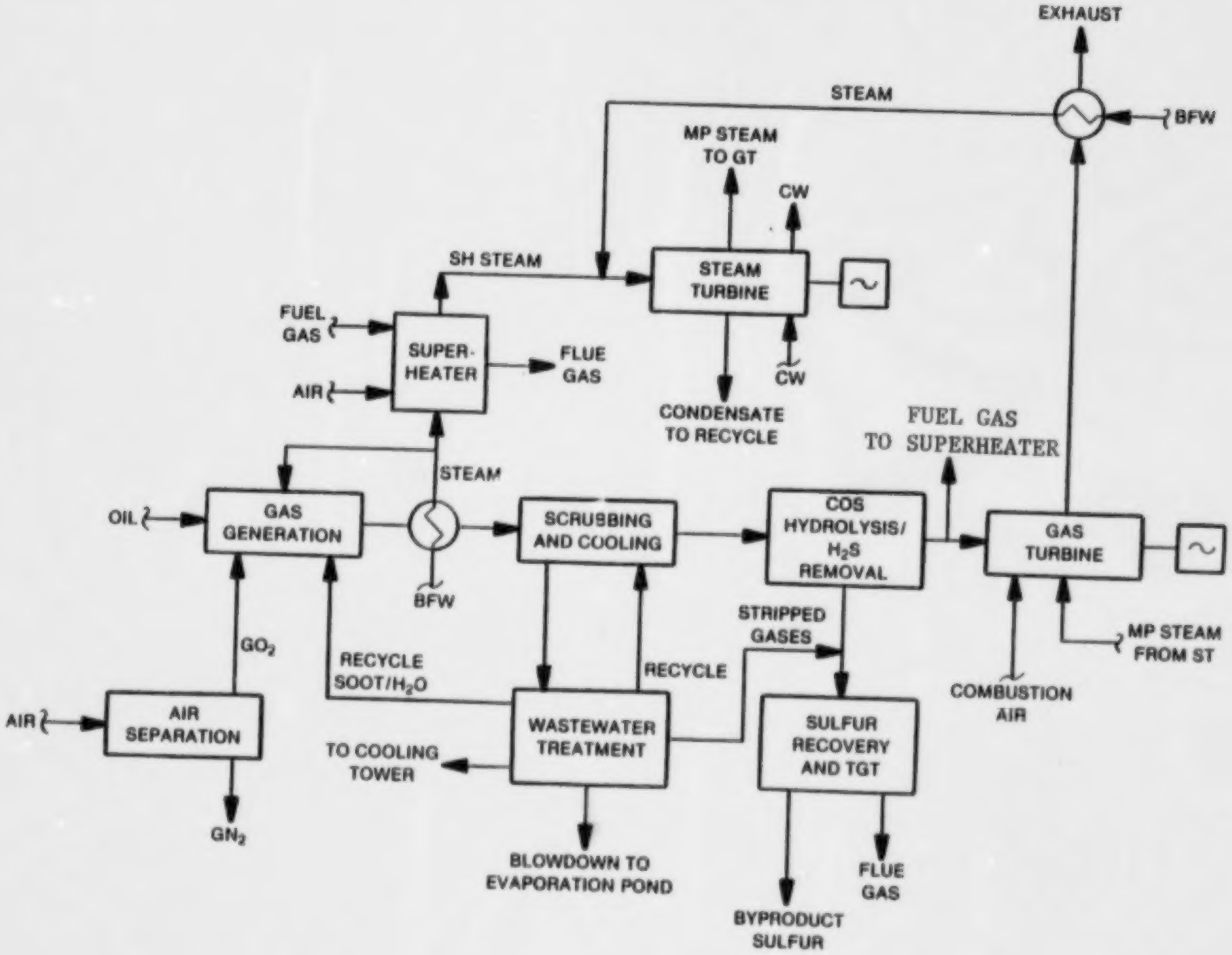

EXHAUST
STEAM
BFW
MP STEAM TO GT
CW
SH STEAM
STEAM TURBINE
~
FUEL GAS
SUPER-HEATER
FLUE GAS
AIR
CW
CONDENSATE TO RECYCLE
FUEL GAS TO SUPERHEATER
STEAM
OIL
GAS GENERATION
SCRUBBING AND COOLING
COS HYDROLYSIS/ H_2S REMOVAL
GAS TURBINE
~
BFW
STRIPPED GASES
GO$_2$
RECYCLE SOOT/H_2O
RECYCLE
MP STEAM FROM ST
COMBUSTION AIR
AIR
AIR SEPARATION
WASTEWATER TREATMENT
SULFUR RECOVERY AND TGT
TO COOLING TOWER
GN$_2$
BLOWDOWN TO EVAPORATION POND
FLUE GAS
BYPRODUCT SULFUR

Figure 7-1. Simplified flow diagram of electricity production via oil partial oxidation/combined cycle turbines

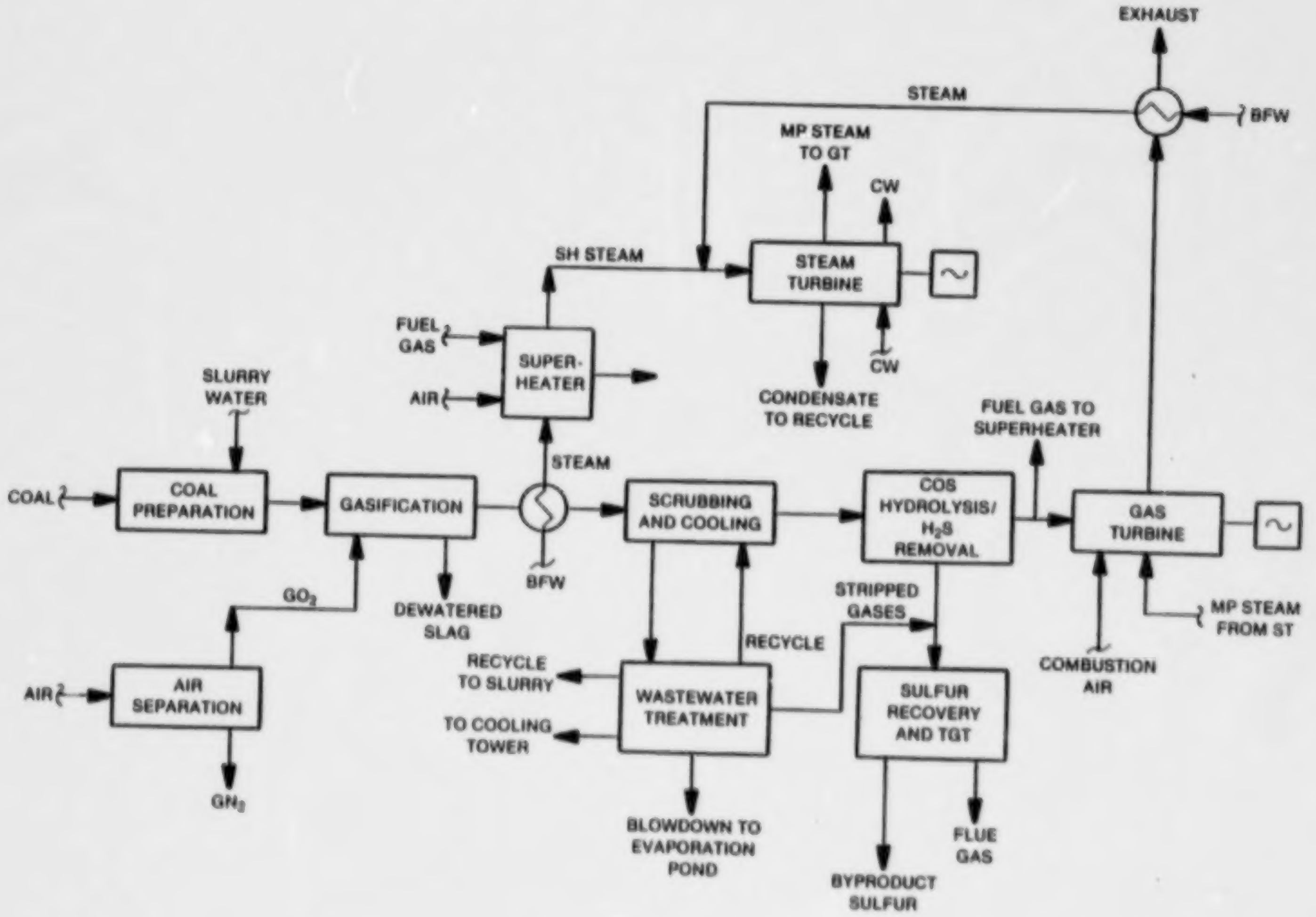

EXHAUST
STEAM
BFW
MP STEAM TO GT
CW
SH STEAM
STEAM TURBINE
FUEL GAS
SUPER-HEATER
AIR
CW
CONDENSATE TO RECYCLE
SLURRY WATER
FUEL GAS TO SUPERHEATER
STEAM
COAL
COAL PREPARATION
GASIFICATION
SCRUBBING AND COOLING
COS HYDROLYSIS/ H_2S REMOVAL
GAS TURBINE
BFW
GO_2
DEWATERED SLAG
STRIPPED GASES
MP STEAM FROM ST
RECYCLE
RECYCLE TO SLURRY
COMBUSTION AIR
AIR
AIR SEPARATION
WASTEWATER TREATMENT
SULFUR RECOVERY AND TGT
TO COOLING TOWER
GN_2
BLOWDOWN TO EVAPORATION POND
FLUE GAS
BYPRODUCT SULFUR

Figure 7-2. Simplified flow diagram of electricity production via coal gasification/combined cycle turbines

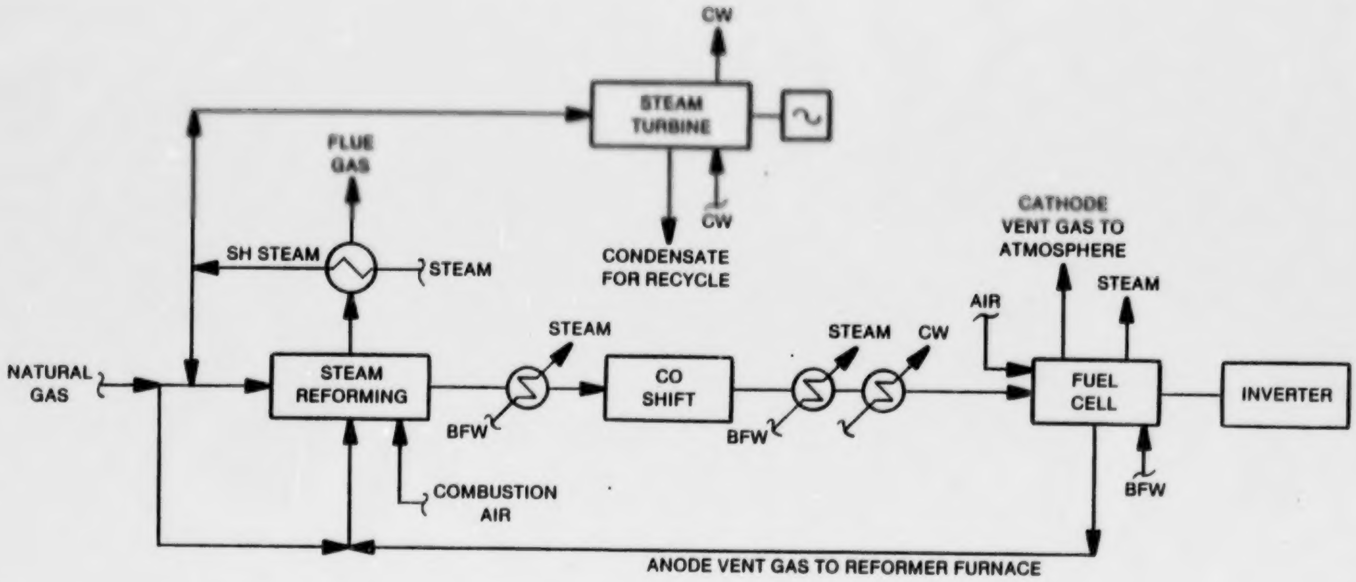

CW
STEAM TURBINE
FLUE GAS
CW
CATHODE VENT GAS TO ATMOSPHERE
SH STEAM
STEAM
CONDENSATE FOR RECYCLE
STEAM
AIR
STEAM
STEAM
CW
NATURAL GAS
STEAM REFORMING
CO SHIFT
FUEL CELL
INVERTER
BFW
BFW
COMBUSTION AIR
BFW
ANODE VENT GAS TO REFORMER FURNACE

Figure 7-3. Simplified flow diagram of electricity production via natural gas steam reforming/fuel cells

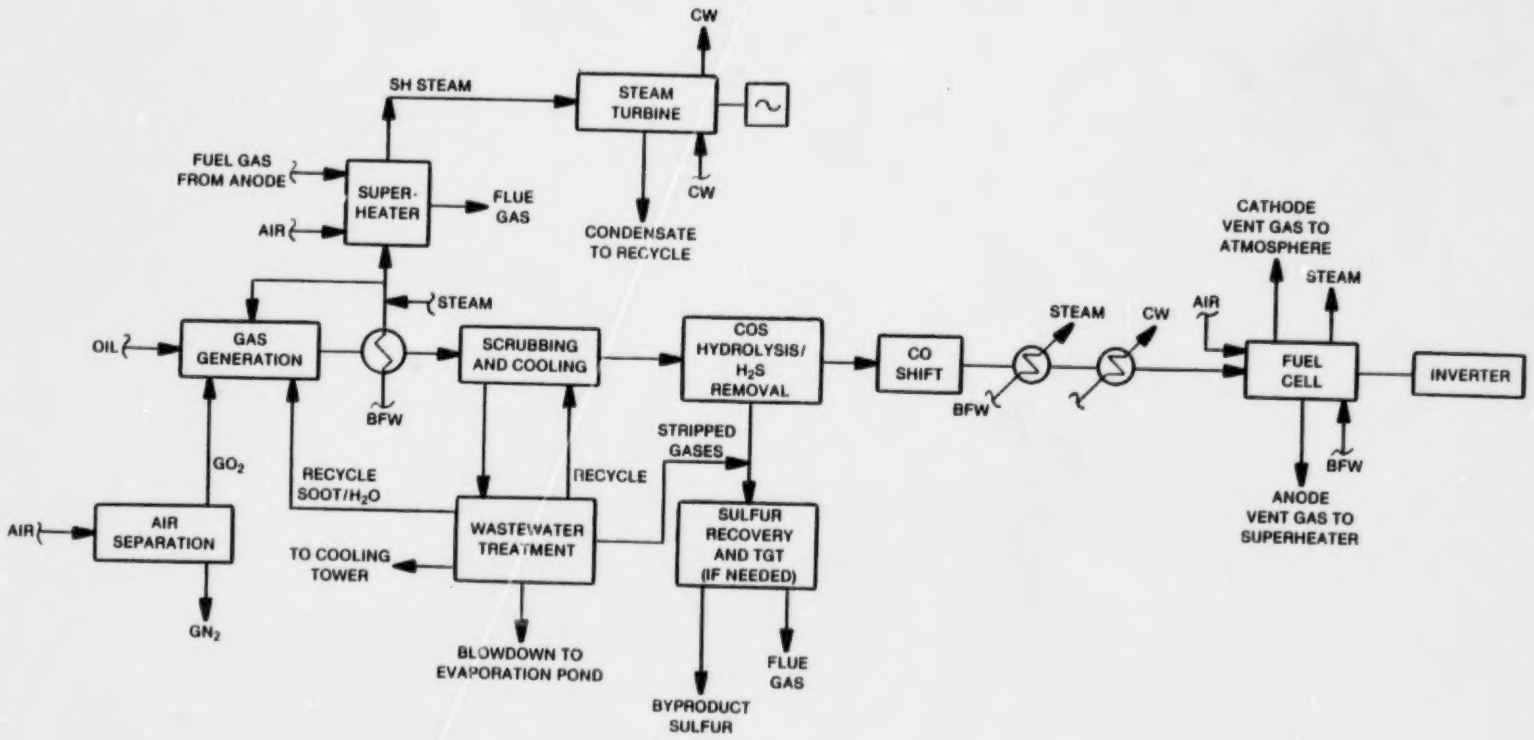

CW
SH STEAM
STEAM TURBINE
FUEL GAS FROM ANODE
SUPER-HEATER
FLUE GAS
AIR
CW
CONDENSATE TO RECYCLE
CATHODE VENT GAS TO ATMOSPHERE
STEAM
STEAM
STEAM
CW
AIR
OIL
GAS GENERATION
SCRUBBING AND COOLING
COS HYDROLYSIS/ H_2S REMOVAL
CO SHIFT
FUEL CELL
INVERTER
BFW
BFW
STRIPPED GASES
BFW
GO_2
RECYCLE SOOT/H_2O
RECYCLE
ANODE VENT GAS TO SUPERHEATER
AIR
AIR SEPARATION
WASTEWATER TREATMENT
SULFUR RECOVERY AND TGT (IF NEEDED)
TO COOLING TOWER
GN_2
BLOWDOWN TO EVAPORATION POND
FLUE GAS
BYPRODUCT SULFUR

Figure 7-4. Simplified flow diagram of electricity production via oil partial oxidation/ fuel cells

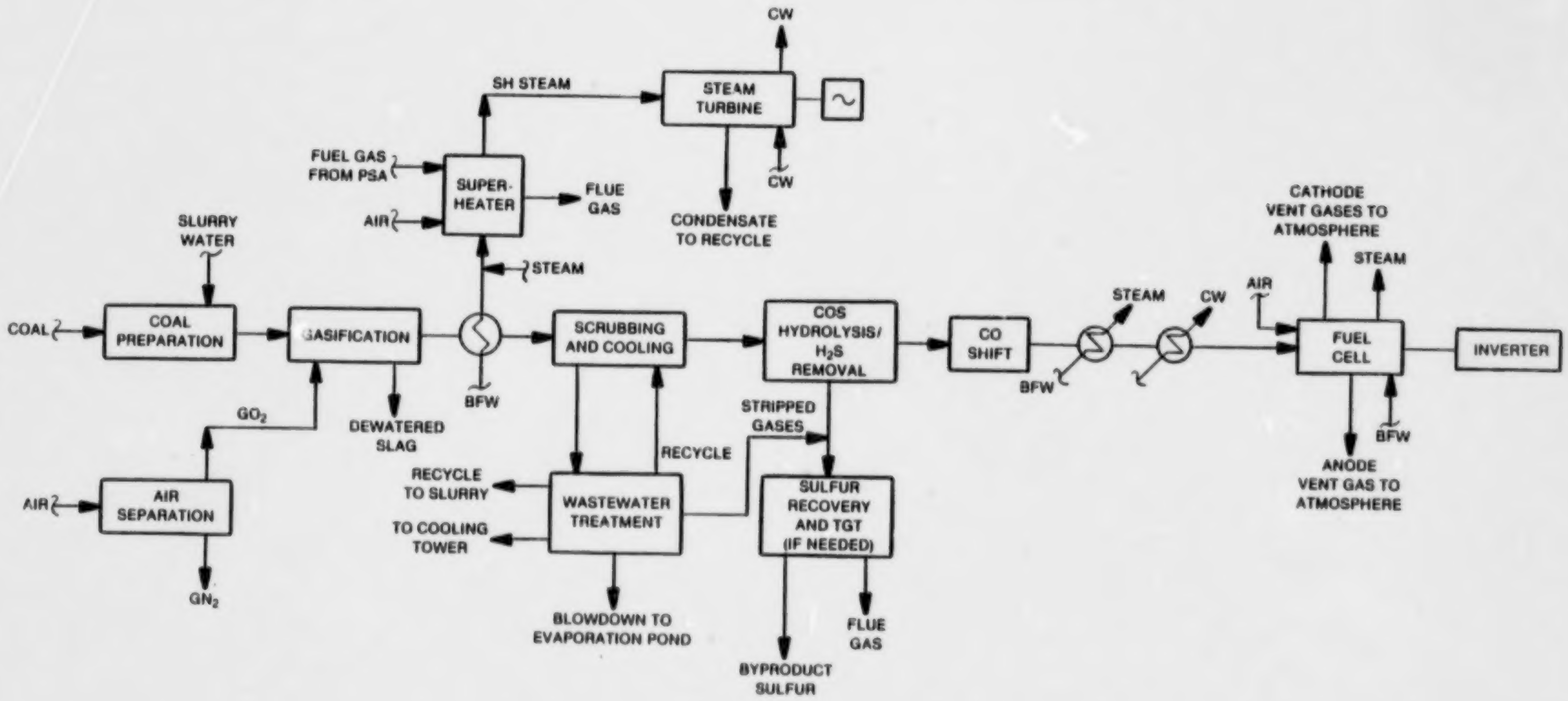
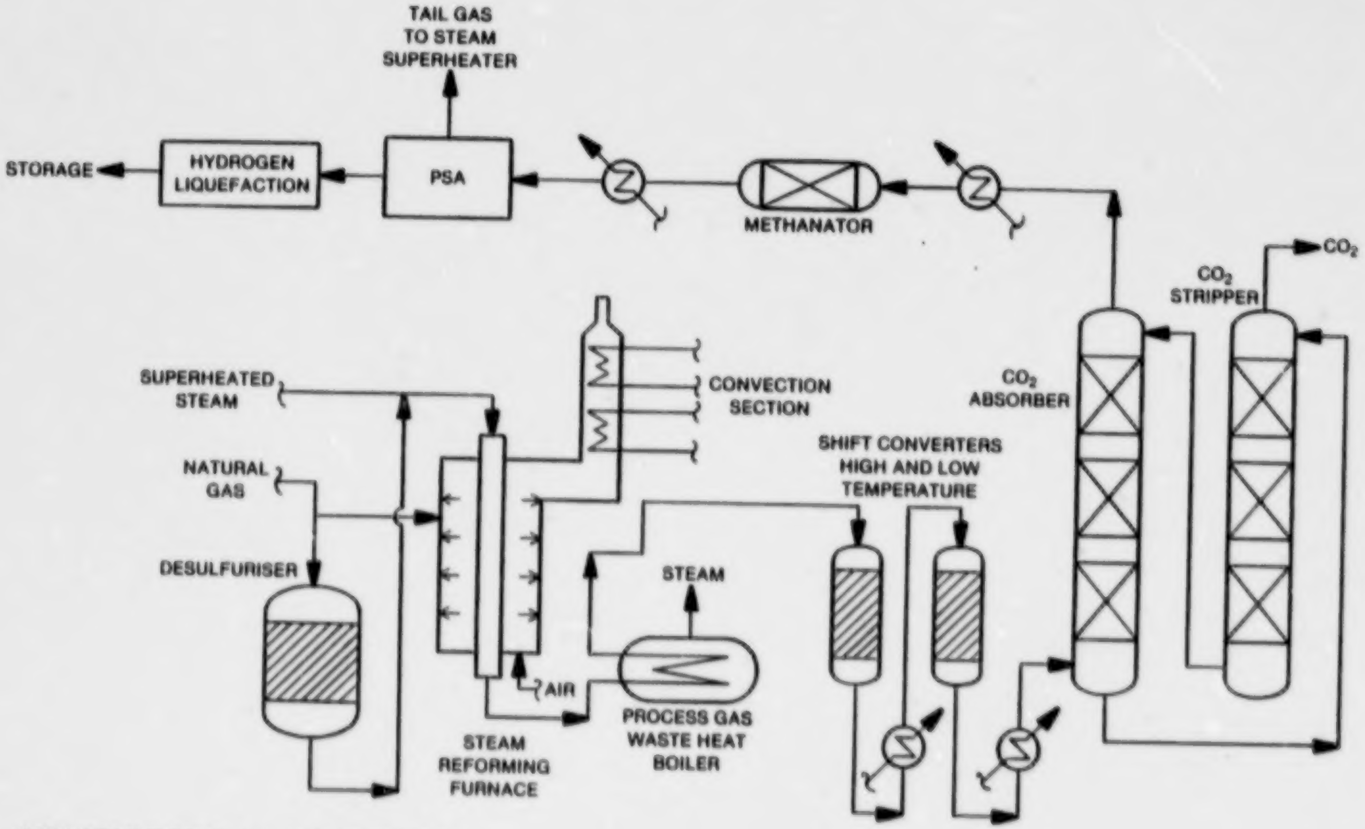

COAL
COAL PREPARATION
SLURRY WATER
GASIFICATION
AIR
AIR SEPARATION
GO_2
GN_2
DEWATERED SLAG
BFW
STEAM
FUEL GAS FROM PSA
AIR
SUPER-HEATER
FLUE GAS
SH STEAM
STEAM TURBINE
CW
CW
CONDENSATE TO RECYCLE
SCRUBBING AND COOLING
WASTEWATER TREATMENT
RECYCLE
RECYCLE TO SLURRY
TO COOLING TOWER
BLOWDOWN TO EVAPORATION POND
COS HYDROLYSIS/ H_2S REMOVAL
STRIPPED GASES
SULFUR RECOVERY AND TGT (IF NEEDED)
BYPRODUCT SULFUR
FLUE GAS
CO SHIFT
BFW
STEAM
CW
AIR
FUEL CELL
CATHODE VENT GASES TO ATMOSPHERE
STEAM
BFW
ANODE VENT GAS TO ATMOSPHERE
INVERTER

Figure 7-5. Simplified flow diagram of electricity production via coal gasification/fuel cells


TAIL GAS
TO STEAM
SUPERHEATER
STORAGE
HYDROGEN LIQUEFACTION
PSA
METHANATOR
CO_2
CO_2 STRIPPER
CO_2 ABSORBER
SUPERHEATED STEAM
NATURAL GAS
DESULFURISER
CONVECTION SECTION
SHIFT CONVERTERS HIGH AND LOW TEMPERATURE
STEAM
AIR
STEAM REFORMING FURNACE
PROCESS GAS WASTE HEAT BOILER

NOTE: STEAM TURBINE AUXILIARY NOT SHOWN.

Figure 7-6. Simplified flow diagram of hydrogen production via natural gas steam reforming

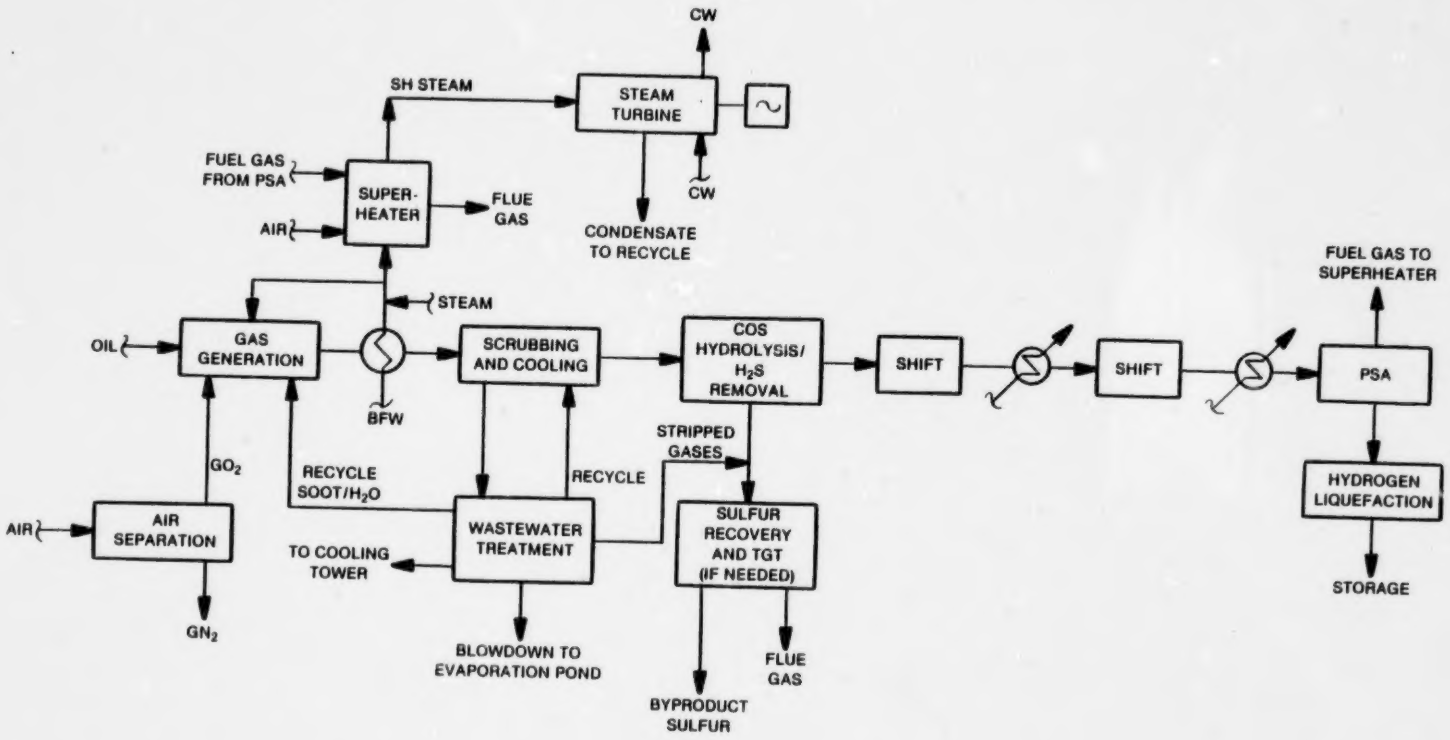

CW
SH STEAM
STEAM TURBINE
FUEL GAS FROM PSA
SUPER-HEATER
FLUE GAS
AIR
CW
CONDENSATE TO RECYCLE
FUEL GAS TO SUPERHEATER
STEAM
OIL
GAS GENERATION
SCRUBBING AND COOLING
COS HYDROLYSIS/ H_2S REMOVAL
SHIFT
SHIFT
PSA
BFW
STRIPPED GASES
GO_2
RECYCLE SOOT/H_2O
RECYCLE
HYDROGEN LIQUEFACTION
AIR
AIR SEPARATION
WASTEWATER TREATMENT
SULFUR RECOVERY AND TGT (IF NEEDED)
TO COOLING TOWER
STORAGE
GN_2
BLOWDOWN TO EVAPORATION POND
FLUE GAS
BYPRODUCT SULFUR

Figure 7-7. Simplified flow diagram of hydrogen production via oil partial oxidation

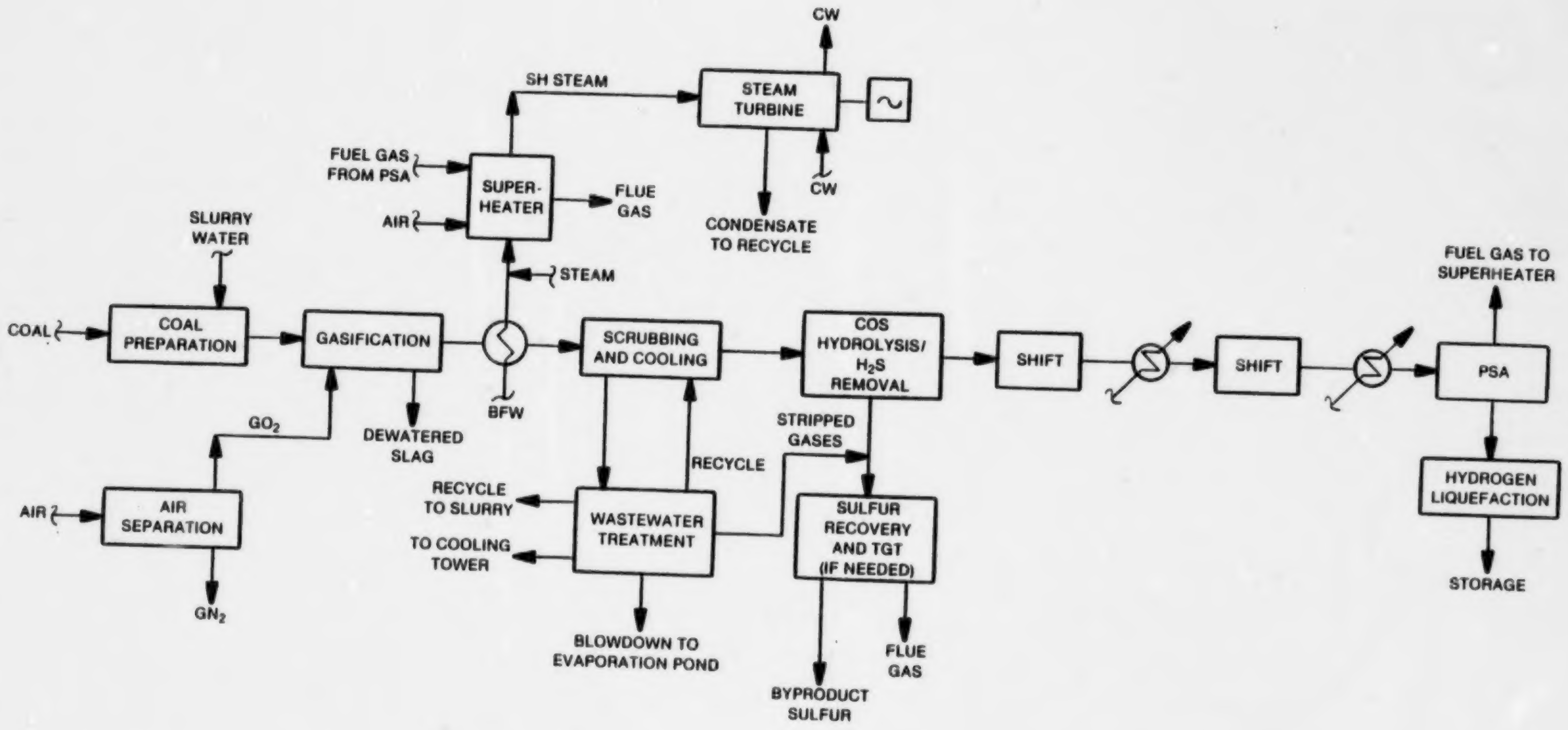

SH STEAM
CW
STEAM TURBINE
FUEL GAS FROM PSA
SUPER-HEATER
FLUE GAS
AIR
CW
CONDENSATE TO RECYCLE
SLURRY WATER
STEAM
FUEL GAS TO SUPERHEATER
COAL
COAL PREPARATION
GASIFICATION
SCRUBBING AND COOLING
COS HYDROLYSIS/ H_2S REMOVAL
SHIFT
SHIFT
PSA
BFW
GO_2
DEWATERED SLAG
STRIPPED GASES
RECYCLE
RECYCLE TO SLURRY
AIR
AIR SEPARATION
WASTEWATER TREATMENT
SULFUR RECOVERY AND TGT (IF NEEDED)
HYDROGEN LIQUEFACTION
TO COOLING TOWER
STORAGE
GN_2
BLOWDOWN TO EVAPORATION POND
FLUE GAS
BYPRODUCT SULFUR

Figure 7-8. Simplified flow diagram of hydrogen production via coal gasification

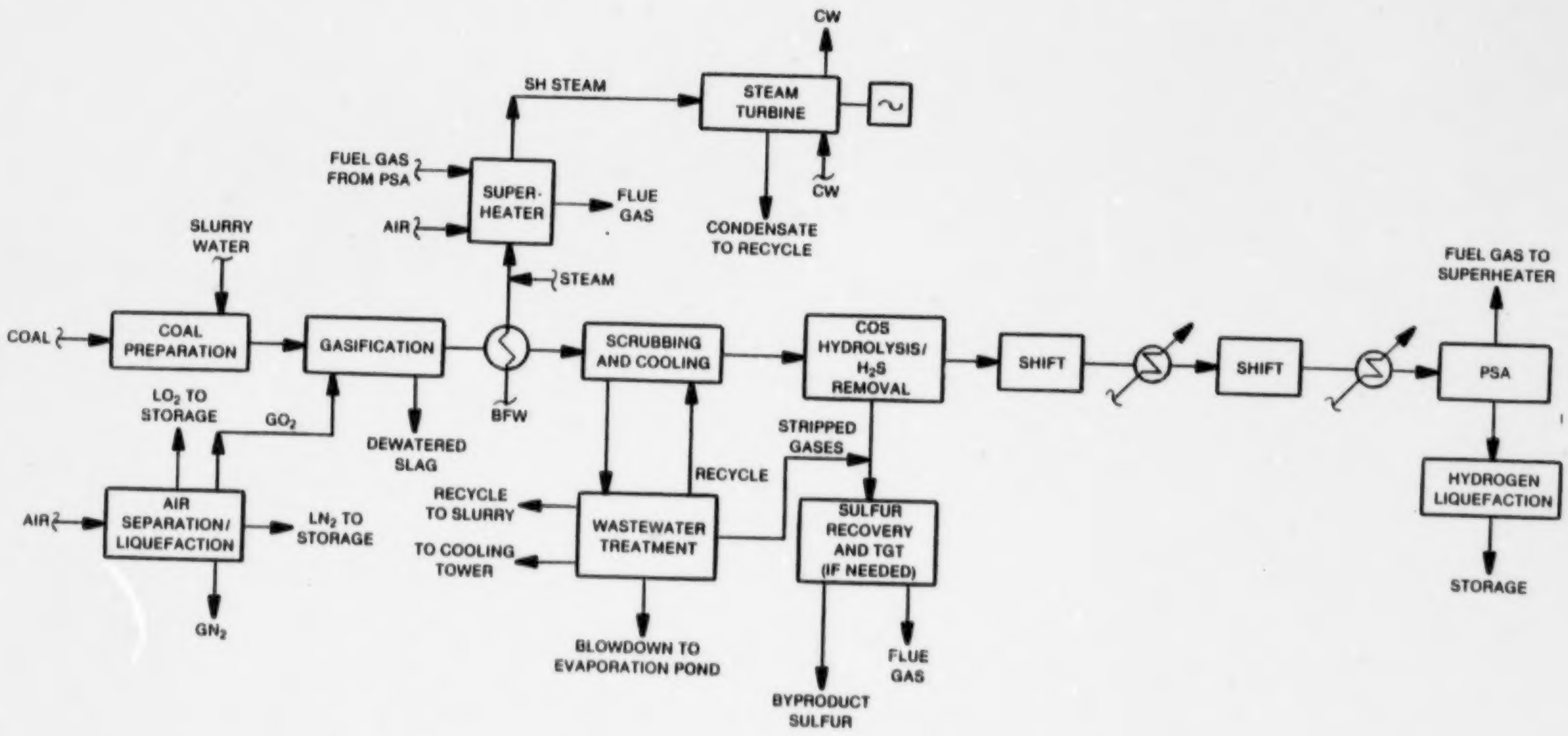

CW
SH STEAM
STEAM TURBINE
~
FUEL GAS FROM PSA
AIR
SUPER-HEATER
FLUE GAS
CW
CONDENSATE TO RECYCLE
SLURRY WATER
STEAM
FUEL GAS TO SUPERHEATER
COAL
COAL PREPARATION
GASIFICATION
SCRUBBING AND COOLING
COS HYDROLYSIS/ H_2S REMOVAL
SHIFT
SHIFT
PSA
BFW
LO_2 TO STORAGE
GO_2
DEWATERED SLAG
STRIPPED GASES
RECYCLE
HYDROGEN LIQUEFACTION
AIR
AIR SEPARATION/ LIQUEFACTION
LN_2 TO STORAGE
RECYCLE TO SLURRY
TO COOLING TOWER
WASTEWATER TREATMENT
SULFUR RECOVERY AND TGT (IF NEEDED)
STORAGE
GN_2
BLOWDOWN TO EVAPORATION POND
FLUE GAS
BYPRODUCT SULFUR

Figure 7-9. Simplified flow diagram of commodities production: coal gasification and air separation

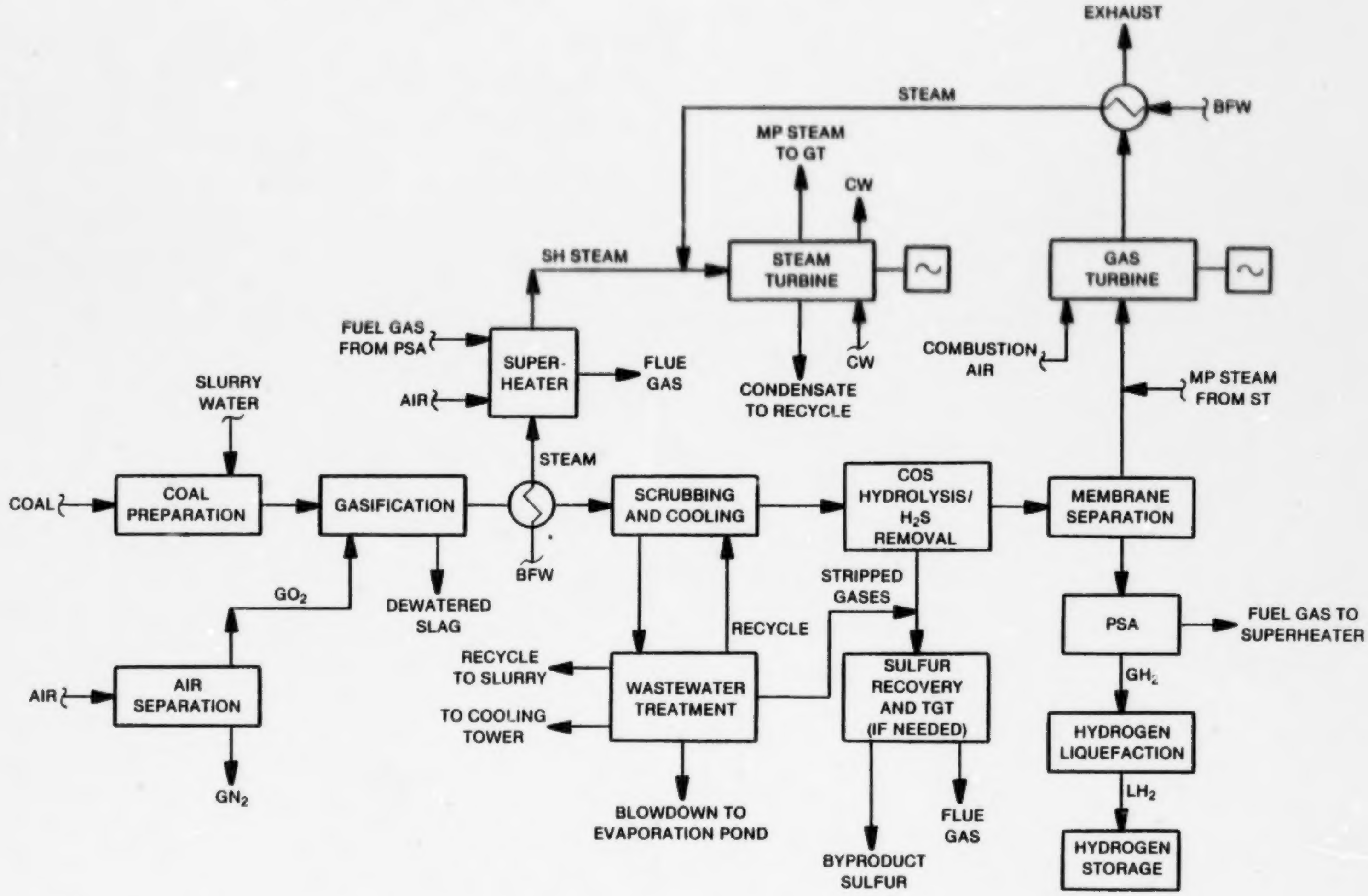

EXHAUST
STEAM
BFW
MP STEAM
TO GT
CW
SH STEAM
STEAM
TURBINE
GAS
TURBINE
FUEL GAS
FROM PSA
SUPER-
HEATER
FLUE
GAS
CW
COMBUSTION
AIR
CONDENSATE
TO RECYCLE
MP STEAM
FROM ST
SLURRY
WATER
AIR
STEAM
COAL
COAL
PREPARATION
GASIFICATION
SCRUBBING
AND COOLING
COS
HYDROLYSIS/
H_2S
REMOVAL
MEMBRANE
SEPARATION
BFW
STRIPPED
GASES
GO_2
DEWATERED
SLAG
RECYCLE
PSA
FUEL GAS TO
SUPERHEATER
RECYCLE
TO SLURRY
WASTEWATER
TREATMENT
SULFUR
RECOVERY
AND TGT
(IF NEEDED)
GH_2
AIR
AIR
SEPARATION
TO COOLING
TOWER
HYDROGEN
LIQUEFACTION
GN_2
LH_2
BLOWDOWN TO
EVAPORATION POND
FLUE
GAS
BYPRODUCT
SULFUR
HYDROGEN
STORAGE

Figure 7-10. Simplified flow diagram of commodities and electricity production, coal gasification and combined cycle turbines

described in the flow diagrams in Figures 7-1 through 7-10. Simple systems with only two or three processing steps are described only in Appendix A.

Most of the electricity production systems in Table 7-1 are conventional and widely applied systems such as those based on the combustion of fossil fuels. These combustion-based systems include conventional boilers (which generate steam for power generation in steam turbines), gas turbines, combined cycle turbines (which include both gas turbines and steam turbines), and diesel engines. Other conventional and widely applied systems for electricity production are wind turbines and pumped hydro storage (which uses water turbines).

Less conventional and less freqently applied systems for the production of electricity include systems based on the conversion of fossil fuels or on the conversion of solar energy. Figures 7-1 and 7-2 show systems which convert liquid or solid fossil fuels to gas which is then combusted and used in combined cycle turbines. Figures 7-3 through 7-5 show systems which convert fossil fuels to a hydrogen rich gas which is processed in fuels cells to produce electricity. (The complexity of the systems shown in Figures 7-1 to 7-5 is one of the factors accounting for their currently minor application.) Solar energy-based systems include solar central receivers (which use solar energy to raise steam for use in steam turbines) and solar photovoltaics (which directly generate electricity).

Systems for the production of commodities (Table 7-2) consist of either complicated systems which process fossil fuels or relatively simple systems which use electricity to process air or water. The fossil fuel based systems are shown in Figures 7-6 through 7-9. These systems (natural gas reforming, oil partial oxidation, and coal gasification) also require electricity from the utility grid mainly for liquefaction of the commodity products. The relatively simple systems (air separation and electrolysis) have higher electricity requirements for both the processing of air and water and for the liquefaction of commodities.

The systems in Table 7-3 produce both electricity and commodities. One of the these systems, shown in Figure 7-10, is essentially the same as the system currently being evaluated for use at the Kennedy Space Center. The other systems producing both commodities and electricity were specified after economic analysis of simple electricity and commodity production options indicated the economic potential of the multiple products concept.

The basic characteristics of fossil fuels considered in this study for use at VAFB are shown in Table 7-4. All of these fuels are widely available and currently used in Californis. These fuel characteristics provide analysis bases for the technical and economic characterizations of candidate systems. The shuttle launch rates, commodity requirements, and electricity demands are also used to establish bases and are shown in Table 7-5.

7.2 TECHNICAL CHARACTERIZATION OF CANDIDATE PRODUCTION SYSTEMS

The candidate production systems are summarily characterized in Table 7-6. Additional technical characterization (including technical references) of the technologies which comprise the candidate systems is contained in Appendix A. The areas of characterization include: development status, conversion efficiency, environmental issues and impacts, reliability, supply vulnerability, and system design capacity. Each of these areas is briefly discussed below.

Development Status

The development status is intended to identify those systems which may have technical risks due to their relative lack of development and application. Systems which are only currently being demonstrated obviously incur a higher technical risk than systems which are commercially well developed and widely applied. All of the systems being considered either have been or are being demonstrated in first generation units, or they are already commercially applied.

TABLE 7-4. BASIC CHARACTERISTICS OF FUELS SELECTED FOR STUDY

Fuel	Characteristics	
Coal	Type: Low sulfur western bituminous (Utah)	
	Composition, as received (wt%):	
	- Moisture	10.0
	- Ash	9.45
	- Carbon	63.2
	- Hydrogen	4.3
	- Nitrogen	1.05
	- Sulfur	0.45
	- Oxygen	11.55
	HHV, as received (Btu/lb)	11,150
	LHV, as received (Btu/lb)	10,640
Natural gas	Composition (vol %):	
	- CO_2	0.92
	- CH_4	90.3
	- C_2H_6	5.65
	- C_3H_8	1.19
	- C_4+	0.37
	- N_2, other	1.55
	HHV (Btu/scf @ 60°F)	1,075
	LHV (Btu/scf @ 60°F)	1,006
No. 2 fuel oil	Composition (wt)	
	- Carbon	87.3
	- Hydrogen	12.6
	- Oxygen	0.04
	- Nitrogen	0.006
	- Sulfur	0.22
	HHV (Btu/lb)	19,300
	LHV (Btu/lb)	18,100
	Specific gravity (°API)	33
No. 6 fuel oil	Composition (wt%)	
	- Carbon	85.7
	- Hydrogen	10.73
	- Oxygen	0.32
	- Nitrogen, ash	0.3
	- Ash	0.3
	- Sulfur	2.65
	HHV (Btu/lb)	18,400
	LHV (Btu/lb)	17,400
	Specific gravity (°API)	15.5

TABLE 7-5. SHUTTLE LAUNCH RATES, COMMODITIES NEEDS, AND ELECTRICITY DEMANDS CONSIDERED IN STUDY

Shuttle Launch Rates	3, 7, and 10 launches per year
Commodities Needs	
LH_2	134 tons per launch
LO_2	1,060 tons per launch
LN_2	640 tons per launch
GN_2[1]	37 tons per day
Electricity Demands	
SLC-6 critical launch demand	9 MW
Continuous VAFB demands	10, 15, and 20 MW

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[1] For blanketing and purging; normal VAFB requirements.

TABLE 7-6. SUMMARY TECHNICAL CHARACTERIZATION OF SYSTEMS CONSIDERED

Production Technology	Development Status	Conversion Efficiency, %[1]	Environmental Issues and Impacts	Reliability, %			Supply Vulnerability	Design Capacities
				Unplanned Outages	Planned Outages	Capacity Factor[2]		
ELECTRICITY PRODUCTION								
Boiler/Steam Turbine	Well developed and widely applied	24-25	BACT[3] can reduce SO_2 and particulate air emissions to low levels but NO_x air emissions would be large enough to require emissions offsets. Use of coal and residual fuel oil results in solid wastes of fly ash and FGD[4] solids; these solids could be classed as hazardous wastes.	10	10	81	All fuels are expected to be available but natural gas and fuel oils may become subject to curtailments.	10, 13.5,[5] 15, and 20 MW
Gas Turbine	Well developed and widely applied	25	NO_x air emissions, although controlled with water injection, would be large enough to require emission offsets. No significant water and solid emissions.	10	5	85.5	Natural gas and fuel oil may become subject to curtailments.	10, 13.5,[5] 15, and 20 MW
Combined Cycle Turbines	Well developed and widely applied except for coal gasification and certain heat recovery components which are currently being demonstrated.	• gas or No. 2 fuel oil-37 • No. 6 fuel oil-31 • Coal-27.5	NO_x air emissions, although controlled with water or steam injection, would be large enough to require emission offsets. Coal and No. 6 fuel oil systems, which feature gasification or partial oxidation, would also generate solid wastes including some potentially hazardous wastes.	• gas or No. 2 fuel oil-10 • Coal or No. 6 fuel oil-15%	10	• gas or No. 2 fuel oil-81 • Coal or No. 6 fuel oil-76.5	All fuels are expected to be available but natural gas and fuel oils may become subject to curtailments.	10, 13.5,[6] 15,[7] and 20 MW
Diesel Engines	Well developed and widely applied	37	NO_x, particulate, and SO_2 air emissions are uncontrolled and would be large enough to require emission offsets. No significant water and solid emissions.	5	5	90.3	Fuel oil may become subject to curtailments.	10, 15, and 20 MW
Fuel Cell	Steam reforming and partial oxidation subsystems are well developed and widely applied but coal gasification, certain heat recovery and fuel cell components are currently being demonstrated.	• gas-37 • No. 6 oil-34 • Coal-32	Air emissions probably are not large enough to require emission offsets. Coal and No. 6 fuel oil systems would generate solid wastes including some potentially hazardous wastes.	• gas-10 • No. 6 fuel oil or coal-15	• gas-5 • No. 6 fuel oil or coal-10	• gas-85.5 • No. 6 fuel oil or coal-76.5	All fuels are expected to be available but natural gas and fuel oils may become subject to curtailments.	10, 13.5,[6] 15,[7] and 20 MW
Wind Turbines	Small turbines (less than about 200 kW) are well developed and widely applied; units up to 4 MW are being demonstrated.	N/A	No air, water, or solid emissions. Possible communications interferences.	10	5	31.5	Wind resource and thus wind turbine power vary widely with frequent interruptions.	10, 15, and 20 MW

(continued)

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TABLE 7-6. (continued)

Production Technology	Development Status	Conversion Efficiency, %[1]	Environmental Issues and Impacts	Reliability, %			Supply Vulnerability	Design Capacities
				Unplanned Outages	Planned Outages	Capacity Factor[2]		
Solar Central Receiver	10 MW demonstration facility is operating and larger commercial plants are planned.	13	No air, water, or solid emissions.	3	5	23	Solar central receiver (or power tower) output varies with changes in direct solar radiation (due to clouding, seasonal & daily variations).	10, 13, and 20 MW
Solar Photovoltaics	Technology is well developed and commercial plants exist and on-going development is aimed at cost reduction.	9	No air, water, or solid emissions.	5	5	25	Solar photovoltaics output varies seasonally and daily.	10, 13, and 20 MW
Pumped Hydro	Well developed and widely applied	70	No air, water, or solid emissions except during construction.	5	5	N/A	Power is available only until reservoir is depleted.	9 and 13 MW
COMMODITIES PRODUCTION								
Steam Reforming	Well developed and widely applied	60	Minor emissions.	5	5	61.7[10]	Natural gas may become subject to curtailments.	3, 7, and 10 launches per year corresponding to 1.79, 4.17, and 5.95 TPD LH_2.
Partial Oxidation	Well developed and widely applied	53	Minor air emissions; solid wastes include potentially hazardous wastes.	10	10	55.6[10]	Fuel oils may become subject to curtailments.	3, 7, and 10 launches per year corresponding to 1.99, 4.64, and 6.63 TPD LH_2 and 27 TPD (3 LPY) and 37 TPD (7 or 10 LPY GN_2.
Coal Gasification	Coal gasification is currently being demonstrated.	50	Minor air emissions; solid wastes include potentially hazardous wastes.	15	10	52.3[10]	Coal supply is expected to be reliable.	3, 7, and 10 launches per year corresponding to 2.11, 4.91, and 7.02 TPD LH_2 and 37 TPD GN_2.
Air Separation	Well developed and widely applied	N/A	No air, water, or solid emissions.	5	5	61.7[10]	Lengthy interruptions in power supply are not expected.	3, 7, and 10 launches per year corresponding to 14.13, 32.97, and 47.10 TPD LO_2 and 8.52, 19.88, and 28.40 TPD LN_2 and 37 TPD GN_2.
Electrolysis	Well developed and commercial plants exist and on-going development is aimed at cost reduction.	80	No air, water, or solid emissions.	5	5	61.7[10]	Lengthy interruptions in power supply are not expected.	3, 7, and 10 launches per year corresponding to 1.79, 4.17, and 5.95 TPD LH_2 and 14.13, 32.97, and 47.10 TPD LO_2.
COMMODITIES AND ELECTRICITY PRODUCTION								
Coal Gasification/ Air Separation	Coal gasification and certain heat recovery components are currently being demonstrated; air separation is widely applied.		Minor air emissions; solid wastes, including potentially hazardous wastes, will be generated.	5[15] 15[16]	5[15] 10[16]	61.7[15] 52.3[16]	Coal supply is expected to be reliable.	10 launches per year only corresponding to 7.02 TPD LH_2, 37 TPD GN_2, 47.1 TPD LO_2, and 28.4 TPD LN_2.

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TABLE 7-6. (continued)

Production Technology	Development Status	Conversion Efficiency, %[1]	Environmental Issues and Impacts	Reliability, %			Supply Vulnerability	Design Capacities
				Unplanned Outages	Planned Outages	Capacity Factor[2]		
Wind Turbines/ Electrolysis	Individual concepts are well developed but combining concepts has not been demonstrated; backup grid power is required when wind turbines power is inadequate.	N/A	No air, water, or solid emissions.	5[12] 10[13]	5	61.7[10,11] 31.5[13]	Wind resource and thus wind turbine power may vary widely with frequent interruptions; grid power provides sufficient backup.	10, 15, and 20 MW[14] and 3, 7, and 10 launches per year corresponding to 1.70, 6.17, and 5.95 TPD LH$_2$ and 16.13, 32.97, and 47.10 TPD LO$_2$.
Wind Turbines/ Air Separation	Individual concepts are well developed but combining concepts has not been demonstrated; backup grid power is required when wind turbines power is inadequate.	N/A	No air, water, or solid emissions.	5[11] 10[13]	5	61.7[10,15] 31.5[13]	Wind resource and thus wind turbine power vary widely with frequent interruptions; grid power provides sufficient backup.	10, 15, and 20 MW[14] and 3, 7, and 10 launches per year corresponding to 16.13, 32.97, and 47.10 TPD LO$_2$ and 8.32, 19.68, and 28.40 TPD LN$_2$ and 37 TPD GN$_2$.
Coal Gasification/ Combined Cycle Turbine	Coal gasification and certain heat recovery components are currently being demonstrated.		NO$_x$ air emissions, although controlled with water or steam injection, would be large enough to require emission offsets. Solid wastes, including potentially hazardous wastes, will also be generated	13	10	96.3	Coal supply is expected to be reliable.	10, 15, and 20 MW and 10 launches per year only corresponding to 7.02 TPD LH$_2$ and 37 TPD GN$_2$.

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TABLE 7-6. (continued)

[1] Efficiency is defined as $\frac{\Sigma \text{ HHV products}}{\Sigma \text{ HHV all inputs}} \times 100\%$ where HHV is the higher heating value.

[2] Capacity factor is defined as the total production in a given year divided by the total production that could have occurred in a year if the plant were operated at maximum capacity year-round. A percentage value is then determined by multiplying the resulting fraction by 100%. The capacity factor accounts for both unplanned and planned outages, and also accounts for extra capacity designed into a plant to provide spare capacity or an extra safety margin.

[3] Best available control technology.

[4] Flue gas desulfurization.

[5] Smallest capacity able to supply critical launch demands at 95% reliability.

[6] Atmospheric fluidized-bed combustion.

[7] Electrostatic precipitator.

[8] Smallest capacity of gas or No. 2 fuel oil system able to supply critical launch demands at 95% reliability.

[9] Smallest capacity of No. 6 fuel oil or coal system able to supply critical launch demands at 95% reliability.

[10] Low capacity factor reflects sizing of plant to support launch rate more frequent than indicated by expected yearly launch rate.

[11] Small steam turbine generators use by-product steam to generate a portion of the plant's power requirement.

[12] For electrolysis only.

[13] For wind turbines only.

[14] Reported capacities are average production capacities available for export to VAFB; previous systems were described by maximum production capacities.

[15] For air separation only.

[16] For coal gasification only.

Conversion Efficiency

Obviously, the conversion efficiency has a direct impact on the economic viability of the candidate systems. The system conversion efficiencies in Table 7-6 were developed from conceptual, overview mass and energy balances. The relatively low efficiencies in Table 7-6 are a consequence of the small size of the systems considered for VAFB. For example, because of their size, the steam turbine systems are constrained to use non-reheat turbines; these turbines are inherently less efficient than the single and double reheat turbine systems used in large electric utilities. (The steam turbines in this study are also constrained to use a lower quality steam than available from larger steam boilers, further reducing the overall conversion efficiency.)

Environmental Issues and Impacts

As discussed in Section 4, the systems considered in this study are designed to minimize environmental impacts by 1) using stringent or best available air pollution control technologies and 2) avoiding the discharge of aqueous wastes. Despite these provisions, some of the systems would emit NO_x air emissions in quantities that would require emission offsets. These offsets may not be readily available at VAFB or may be available only at high cost. Some systems would produce solid wastes which could be classed as hazardous, thus requiring special handling, treatment, and disposal. Several of the production systems (mainly those not based on fossil fuels) have essentially no air, water, or solid emissions.

Reliability (Out of Service Time)

The planned and unplanned outage rates are based on engineering judgement and on the Electric Power Research Institute's Technical Assessment Guide (7-1). As shown in Table 7-6, these reliability data directly determine the maximum plant capacity or operating factor and thus have a major impact on the economic viability of candidate systems. These data also determine the numbers of units required to meet the critical launch reliability constraint, and thus have a second impact on economic viability.

Supply Vulnerability

The resources for the candidate production systems are all expected to be generally available in the near and long-term, but certain resources may be subject to curtailments or interruptions. The fossil fuels resources natural gas and fuel oils, for example, may be subject to curtailments during nationwide or regional energy shortages. As discussed in Section 3, while lengthy interruptions in electrical power supplied by utility grids are unlikely, short power blackouts and brownouts could significantly reduce short-term grid reliability and supply. The wind resource and thus wind turbine power obviously vary both daily and seasonally with frequent power interruptions. Solar resources also vary seasonally and daily but with less frequent variations than the wind resource.

Design Capacities

These are the specific design capacities of production systems considered in this study.

7.3 ECONOMIC CHARACTERIZATION OF CANDIDATE PRODUCTION SYSTEMS

After ensuring power availability, the economic viability of the candidate production systems is probably the most important factor determining the suitability of their use at VAFB: the economic characterization in effect incorporates the results of most of the technical analysis of the candidate systems. For example, the system conversion efficiency (and other mass and energy balances) directly affects the sizing and thus the cost of system equipment components. The environmental analysis directly affects the selection, design, and thus costs of all environmental control equipment components. As stated above, the reliability analysis determines the number of units required to meet critical launch electrical demands and also establishes the maximum plant capacity or operating factor; both of these effects have major influences on system economic viability. The issue of fuel/feedstock supply vulnerability is indirectly measured by the market structure of prices; and since these prices are used in the economic analysis, supply vulnerability is also indirectly considered in the economic analysis. Obviously, the design capacities of the candidate systems also have a major and direct impact on the economic analysis.

The overall approach for performing an economic analysis or characterization of candidate production systems is explained in Section 7.3.1. Also included in Section 7.3.1 are detailed bases for the economic analyses. Sections 7.3.2 presents the principal results of the economic analysis; complete results for the over 250 economic analyses (including sensitivity analyses) are contained in Appendix B.

7.3.1 Economic Approach and Bases

In this study, the economic viability of the candidate production systems was determined through standard discounted cash flow (DCF) analysis of all of the costs and "revenues" associated with the candidate systems. The revenues of each system are the values of the system products (electricity or commodities); these product values are equal to the prices that would be paid for the system products if they continued to be purchased. In the standard DCF analysis, the yearly negative costs and positive revenues of each system over its economic lifetime are discounted to a base period and summed. The sum is the net present value (NPV) of the production system. When the NPV is positive, the candidate production system is justified based on its capability to reduce overall expenditures over the life of the project. When the NPV is negative, the system is not economically viable. In comparing similar systems with positive NPVs, the systems with the larger positive values are more desirable. Under this approach, when the NPV is zero, the benefits of the on-site production system are exactly balanced by its cost.

Detailed bases for the economic analysis are presented in Tables 7-7 through 7-13. Table 7-7 defines the major equipment components of the candidate production systems and identifies the cost references used for each equipment component. Table 7-8 defines the components included in the total capital investment and Table 7-9 defines the components of the annual cash flows. Table 7-10 illustrates the calculation of total capital investment, annual cash flows, and net present value of yearly net cash flows. Table 7-11 presents several economic and cost bases and Table 7-12 presents bases for operating labor requirements, maintenance costs, and construction periods. Table 7-13 shows the number of units required to meet critical launch power demands. Additional background on the cost estimating approach and the overall DCF/NPV analysis is presented below.

7.3.1.1 Cost Estimating--As shown in Table 7-7, equipment costs of the various systems were estimated from a number of references including Radian in-house sources, various technical literature, several NASA cost studies, and vendors and process developers. Costs from these basic references were first updated to consistent design and cost bases. These costs were then correlated with system mass and energy balances to yield cost estimating equations or algorithms. Using the mass and energy balances of the specific systems considered in this study, the cost algorithms were then used to estimate the costs of the candidate production systems. Additional elements of the total capital investment (Table 7-8) were estimated with standard cost engineering assumptions as fractions of the direct or indirect costs. The estimated total capital investment is an order-of-magnitude estimate, with an estimated accuracy of ±50 percent.

Annual expenses and revenues (Table 7-9) were similary estimated. The bases for these annual cash flows are the overall mass and energy balances and the factors in Table 7-11 and Table 7-12.

TABLE 7-7. MAJOR SYSTEM COMPONENTS AND COST REFERENCES

Production Technology	Major System Components	Cost References[a]
ELECTRICITY PRODUCTION		
Boiler/Steam Turbine	• Steam turbine/generator set and all auxiliaries	• Mitsubishi (2), Guthrie (3), and IFDP (4)
	• Boiler and all auxiliaries (such as feedwater and condensate handling/treatment systems, fans, and stack)	• Radian (5-7)
	• Fuel unloading, storage, preparation, and feed equipment	• Radian (5-7), Kaiser (8)
	• Ash handling equipment (for No. 6 oil and coal systems)	• Radian (5-7)
	• Cooling water system and tower	• Guthrie (3)
	• Gas pipelines (natural gas system only)	
	• Electrical switchgear, transformer, and transmission line	• Kaiser (8) and Stewart and Stevenson (9)
	• Air emission control equipment - lime dual alkali wet scrubbing for SO_2 removal in fuel oil systems; ESP used for particulate removal in No. 6 fuel oil system - lime spray drying for SO_2 removal in stoker coal systems; baghouse used for particulate removal - baghouse used for particulate removal in AFBC coal systems (SO_2 removal is inherent in AFBC concept) - NO_x removal by range of combustion modifications for all systems	• Radian (5)
Gas Turbines	• Gas turbine/generator set and all auxiliaries	• Kaiser (8), Radian (10)
	• Fuel unloading, storage, preparation, and feed equipment	• Kaiser (8)
	• Electrical switchgear, transformer, and transmission line	• Kaiser (3) and Stewart and Stevenson (9)
	• Gas pipeline (natural gas system only)	
Combined Cycle Turbines	• Steam turbine/generator set and all auxiliaries	• Mitsubishi (2), Guthrie (3), and IFDP (4)
	• Heat recovery boiler and all auxiliaries	• Radian (11)
	• Fuel unloading, storage, preparation, and feed equipment	• Kaiser (8), Bechtel (12), EPRI (13), Fluor (14), and SD (15)
	• Cooling water system and tower	• Guthrie (3)
	• Gas pipeline (natural gas system only)	
	• Electrical switchgear, transformer, and transmission line	• Kaiser(8) and Stewart and Stevenson (9)
	• Gas turbine/generator set and all auxiliaries	• Kaiser (8), Radian (10)
	• Coal gasification plant and all auxiliaries (including O_2 plant, coal gasification and ash removal, gas cooling and washing, sulfur removal and recovery, wastewater treatment, air pollution control equipment such as tail gas treatment in sulfur plant, support facilities)	• EPRI (13), Fluor (14), and SD (15)
	• Oil partial oxidation plant and all auxiliaries (including O_2 plant, gas generation and quench, heat recovery, sulfur removal and recovery, wastewater treatment, air pollution control equipment and support facilities)	• Bechtel (12)

(continued)

TABLE 7-7. (continued)

Production Technology	Major System Components	Cost References[a]
Diesel Engine	• Engine/generator set and all auxiliaries	• Kaiser (8), Fairbanks and Morse (11), and Guthrie (3)
	• Fuel unloading, storage, and feed equipment	• Kaiser (8)
	• Electrical switchgear, transformer, and transmission line	• Kaiser (8) and Stewart and Stevenson (9)
Fuel Cell	• Similar to that listed for combined cycle turbines above with deletion of gas turbine/generator set and auxiliaries and addition of the following components	• See above for combined cycle turbines
	• Fuel cell, inverter, fuel cell heat removal, and all fuel cell auxiliaries	• EPRI/KTI (16)
	• High temperature shift reactors and auxiliaries (added to gasification and partial oxidation)	• Bechtel (12), and SD (15)
	• Gas steam reforming plant and all auxiliaries (reformer, high temperature shift, process gas steam generator and auxiliaries, PSA unit and auxiliaries, support facilities)	• KTI (17)
Wind Turbines	• Wind turbine/generator sets and all auxiliaries	• Carter (18)
	• Electrical switchgear, transformer and transmission line	• Kaiser (8) and Stewart and Stevenson (9)
Solar Central Receiver (Power Tower)	• Complete system (tracking heliostats, central receiver/boiler, steam turbine/generator set and auxiliaries, condenser and cooling water system and tower, thermal storage)	• CEC (19)
	• Electrical switchgear, transformer, and transmission line	• Kaiser (8) and Stewart and Stevenson (9)
Solar Photovoltaics	• Complete flat-plate PV system	• ARCO Solar (20), CEC (19), and JPL (21)
	• Electrical switchgear, transformer, and transmission line	• Kaiser (8) and Stewart and Stevenson (9)
Pumped Hydro Storage	• Reservoir, turbine/generator and auxiliaries	• GE (22) and Public Service Electric & Gas (23)
	• Electrical switchgear, transformer, and transmission line	• Kaiser (8) and Stewart and Stevenson (9)
COMMODITIES PRODUCTION		
Steam Reforming, Partial Oxidation, and Gasification	• Similar to those listed for fuel cell systems above with deletion of fuel cell, inverter, fuel cell heat removal, and fuel cell auxiliaries, and electrical switchgear, transformer, and transmission line, and addition of the following components	• See above for fuel cell systems
	• Hydrogen liquefaction system and all auxiliaries	• E:F Technologies (24)
	• PSA units and auxiliaries (added to gasification and partial oxidation)	• Bechtel (12) and SD (15)

(continued)

TABLE 7-7. (continued)

Production Technology	Major System Components	Cost References[a]
Air Separation	● Air separation and liquefaction and all auxiliaries	● Union Carbide (25)
Electrolysis	● Electrolyzers, power conditioning equipment, and all	● E:F Technologies (24)
COAL GASIFICATION/AIR SEPARATION	See individual production technologies above for system components and cost references.	
COGENERATION/POLYGENERATION		
Wind Turbines/Electrolysis, Wind Turbines/Air Separation, Coal Gasification/Combined Cycle Turbine,	See individual production technologies above for system components and cost references (but note that membrane separation is substituted for shift reactors in coal/gasification/combined cycle turbine concept)	

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[a] References are listed at end of Section 7.

TABLE 7-8. COMPONENTS OF TOTAL CAPITAL INVESTMENT

- Direct Costs
  - Delivered Equipment (equipment, taxes, and freight)
  - Equipment Installation (labor and materials)
    - Instruments
    - Foundations and supports
    - Erection and handling
    - Electrical
    - Buildings
    - Piping
    - Insulation
    - Painting
    - Site development
- Indirect Costs
  - Engineering and Supervision
    - Construction design and engineering
    - Drafting
    - Purchasing
    - Accounting
    - Travel
    - Cost engineering
    - Home office expenses
  - Field Construction Expenses
    - Temporary construction
    - Construction tools and rental
    - Construction payroll, travel, and living
    - Construction overhead
  - Contingency
  - Contractor's Fee
- Interest During Construction
- Startup and Modifications
- Working Capital

TABLE 7-9. COMPONENTS OF ANNUAL CASH FLOWS

Revenues

- Liquid Hydrogen
- Liquid Oxygen
- Liquid Nitrogen
- Gaseous Nitrogen
- Electricity

Expenses

Non-Fuel

- Operating materials
- Operating labor
- Supervising labor
- Maintenance materials/ replacement parts
- Off-site waste disposal
- Process water
- Cooling water
- Labor overhead
- Plant overhead

Fuel

- Electricity
- No. 2 fuel oil
- No. 6 fuel oil
- Natural Gas
- Coal

TABLE 7-10. EXAMPLE COST AND ECONOMIC ANALYSIS

TABLE XYZ. COAL FIRED STOKER BOILER STEAM TURBINE

TOTAL SIZE, MW	13.5		
NO. OF UNITS	3		
UNIT SIZE, MW	4.5	DISCOUNT RATE, %	11.75
CAPACITY FACTOR, %	81.00	INFLATION RATE, %	6
DESIGN/CONSTR TIME, YR	2		
TOTAL PLANT COST,'83 $	29		
INT. DURING CONSTR	1.66		
STARTUP % MODS	1.46		
TOTAL DEPR. INVESTMENT			
MID-83 $	32		
JAN-92 $	53		
WORKING CAP., JAN-92 $	2		
TCI, JAN-92 $	55		

YEAR	REVENUES	EXPENSES			NET CASH	PRESENT VALUE OF NCF JAN 1992 $	
		FUEL	NON-FUEL	TOTAL	FLOW	YEARLY	CUM.
JAN 1992							-55
1992	12	8	5	13	-1	-1	-56
1993	13	9	5	15	-2	-1	-57
1994	14	10	6	16	-2	-2	-59
1995	14	11	6	17	-3	-2	-61
1996	15	12	6	19	-3	-2	-63
1997	17	13	7	20	-4	-2	-65
1998	18	14	7	22	-4	-2	-66
1999	19	16	8	23	-4	-2	-68
2000	21	17	8	25	-5	-2	-70
2001	22	19	9	27	-5	-2	-71
2002	23	20	9	29	-6	-2	-73
2003	25	22	10	31	-7	-2	-75
2004	27	24	10	34	-7	-2	-77
2005	28	26	11	37	-8	-2	-78
2006	30	28	12	39	-9	-2	-80
2007	32	30	12	42	-10	-2	-82
2008	34	33	13	46	-11	-2	-84
2009	36	35	14	49	-13	-2	-85
2010	39	38	15	53	-14	-2	-87
2011	41	42	15	57	-16	-2	-89
2012	44	45	16	61	-17	-2	-90
2013	47	49	17	66	-19	-2	-92

PRESENT VALUE OF NCF	-92
PAYBACK PERIOD, YRS	NONE
FRACTION CAP RETURNED	-1.67

TABLE 7-11. ECONOMIC AND COST BASES[1]

Type of Analysis	Discounted Cash Flow/Net Present Value (NPV)
Accuracy	Order of Magnitude (±50%)
Year Basis for NPV	January 1, 1992
Period for Cash Flows	22 Years (to December 31, 2013)
Timing of Cash Flows	Lump-Sum, End-of-Year Values
Type of Financing	Government
Discount Rate	
- baseline	11.75%[2]
- low/high sensitivities	6%/18%
Inflation Rate	6%
Labor Overhead Rate	50% of All Labor Costs
Plant Overhead Rate	25% of All Costs and Maintenance Materials and Labor
Energy/Commodity Prices	See Section 5
Operating Labor/Materials Prices	West Coast U. S. Values
Shuttle Launch Rate	Assumed Constant Over Project Life

[1] Bases for operating labor requirements, and construction periods are shown in Table 7-12.

[2] Based on rate for long-term Treasury bills in late 1983.

TABLE 7-12. BASES FOR OPERATING LABOR REQUIREMENTS, MAINTENANCE COSTS, AND CONSTRUCTION PERIODS

Production Technology	No. of Operators/ Shift	Maintenance Costs % of Total Plant Cost[1]	Design/Construction Period, Years[2]
ELECTRICITY GENERATION			
Boiler/Steam Turbine			
• Coal	5 - 7[3]	3.3	2
• No. 6 fuel oil	4	2.8	2
• No. 2 fuel oil	4	2.8	1
• Natural gas	3	2.5	1
Gas Turbine	2	2.9	1
Combined Cycle Turbines			
• Coal gasification	8 - 10[3]	3.0	3
• Partial oxidation	6	3.0	3
• No. 2 fuel oil or natural gas	4	2.5	1
Diesel Engines	2	1.7	1
Fuel Cells			
• Coal gasification	8 - 10[3]	3.0	3
• Partial oxidation	6	3.0	3
• Steam reforming	2	3.0	1
Wind Turbines	1	3.3	1
Solar Central Receiver (Power Tower)	2	1.5	1
Solar Photovoltaics	1	0.5	1
Pumped Hydro	—	—	3
COMMODITIES PRODUCTION			
Steam Reforming	3	3.0	1
Partial Oxidation	6	3.0	3
Gasification	7 - 9[3]	3.0	3
Air Separation	1	2.0	1
Electrolysis	1	2.0	1
Coal Gasification/Air Separation	10[5]	~3.0	3
COMMODITIES AND ELECTRICITY PRODUCTION			
Wind Turbines/Electrolysis	2	2.0 - 3.3[4]	1
Wind Turbines/Air Separation	2	2.0 - 3.3[4]	1
Coal Gasification/Combined Cycle Turbine	9 - 12[3]	3.0	3

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[1] Total plant cost is equal to the total capital investment excluding interest during construction, startup and modifications, and working capital.

[2] This period covers initial engineering through plant startup.

[3] Range corresponds to range of capacities.

[4] Range corresponds to range of export power capacities.

[5] For 10 launches per year system only.

TABLE 7-13. NUMBER OF UNITS REQUIRED TO SUPPLY CRITICAL LAUNCH POWER DEMANDS[1]

Technology Reliability[2]	Total System Power Demand incl. Critical Launch Demands, MW	Number of Units Required		Total System Power Capacity, MW
		Total	Spare	
95	10	1	0	10
	15	1	0	15
	20	1	0	20
90	10	3	1	13.5
	15	3	1	15
	20	2	1	20
85	10	5	2	15
	15	5	2	15
	20	2	1	20

---

[1] Critical launch power demands of about 9 MW are presumed. The number of units required to supply critical launch power demands with at least a 95% reliability depends on the basic technology reliability and on the total system power demand. The numbers of units shown in this table were determined through straightforward probability analyses using the probabilities of unplanned outages for individual technology units.

[2] Based on reliability data in Table 7-6; technology reliability (as a percentage) is 100 minus the unplanned outage rate of Table 7-6.

7.3.1.2 DCF/NPV Economic Analysis--The overall approach of the DCF/NPV analysis is illustrated in Table 7-10.

The total capital investment was first estimated in 1983 dollars and then escalated to the system startup date (January 1, 1992) with an estimated inflation rate for capital expenses (assumed to be 6 percent per year). The startup date was estimated as the first year of shuttle launches at the nominal design launch rate. (For the systems considered in this study, system startup before the nominal launch rate is achieved is not economically practical.) A different assumption for the base year would change the absolute dollars of the economic analysis but would not alter the overall study findings.

Next, the year-by-year processing expenses and product values were estimated over 22 years using the general inflation rate (assumed to be 6 percent per year) and real escalation rates. The first year estimates are given for December 31, 1992, and subsequent estimates are also lump-sum, end-of-year values rather than average costs over the year. (This standard assumption simplifies the economic calculations.) The 22 year period specified for the period of cash flow analysis is the average, expected useful plant lifetime. Real escalation rates are zero for labor, maintenance, and other non-utility or product components. The product values (LH_2, LN_2, GN_2, LO_2, and electricity) and utility costs (grid power, coal, fuel oils, and natural gas) are escalated with the rates from Section 5. The calculation of cash flows presumes government-only ownership of the production system.

The yearly net cash flow was next calculated by subtracting the sum of the expenses from the sum of the product values for each year. The present value (in January 1, 1992 dollars) of each year's net cash flow was then calculated by multiplying each year n's cash flow by $1/(1+r)^n$ where r is the discount rate. For government ownership, the base case value of the discount rate was presumed to be 11.75 percent. (The base case discount rate is based on the rate for long-term Treasury bills in late 1983.)

The NPV of the production systems is then simply the sum of the annual discounted cash flows including the initial capital investment as a negative cash flow in year 0.

For the candidate systems shown to be viable in the base case economic analyses, additional sensitivity analyses were conducted in the following areas:

- discount rates of 6 or 18 percent
- 50% higher/lower capital costs
- 50% higher/lower annual non-fuel expenses
- higher/lower capacity factors
- low/high fuel, utility, and product prices (based on the scenarios in Section 5)

7.3.2 Economic Analyses

Complete results of the economic analyses are presented in Appendix B. The major results of these analyses are highlighted in this section. Most of the major results describe only the largest systems considered in this report: 20 MW electrical power or commodities for 10 shuttle launches per year. The smaller systems considered in this study generally show the same trends as the largest systems.

The major results are highlighted in a series of figures. The discussions of these results are organized into four sections. Section 7.3.2.1 discusses critical launch demand power systems. Section 7.3.2.2 discusses continuous electricity production systems (which are additionally capable of meeting the critical launch power demands). Section 7.3.2.3 discusses commodity production systems. And Section 7.3.2.4 discusses systems for producing both commodities and electricity.

7.3.2.1 Critical Launch Demand Power Systems--The total capital investments for critical launch demand power systems are shown in Figure 7-11. Only the total capital investments are shown since the operating and maintenance costs are negligible: the systems are presumed to operate only during launch periods. Systems other than those in Figure 7-11 are technically feasible for use as power backups for the critical launch operations, but they clearly have higher total capital investments than those in Figure 7-11.

The relative ranking of these systems varies with the presumed design basis. Depending on these bases, each of these systems is potentially the system of choice based on the lowest capital investment. The two gas turbine systems have very similar costs. Systems sized to produce 13.5 MW would meet the 95% reliability criterion for supplying 9 MW of critical launch power demands. The gas turbine systems would be the least expensive of the four options if: 1) pumped hydro alternatives were required to have capacities greater than 24 to 36 hours (which corresponds to twice or thrice the critical launch demand of about 11 hours), and 2) diesel engine alternatives required multiple units to achieve the 95% reliability criterion. Based on a preliminary analysis, new diesel engines may be more reliable than gas turbines and thus could meet the 95% reliability criterion with single units. But if multiple diesel units were required, equivalent gas turbine systems would be less expensive. Pumped hydro systems would be less expensive than single diesels unless more than 24 hours of pumped hydro storage capacity were needed.

7.3.2.2 Continuous Electricity Production Systems--The total capital investment and net discounted cash flows of continuous electricity production systems are shown in Figures 7-12 through 7-17. Figure 7-12 shows the economic analysis of steam turbine technologies. Figure 7-13 shows the economic analysis of diesels and gas turbines. Figure 7-14 shows the economic analysis of combined cycle technologies and Figure 7-15 shows the economic analysis of fuel cell technologies. Figure 7-16 shows the economic analysis

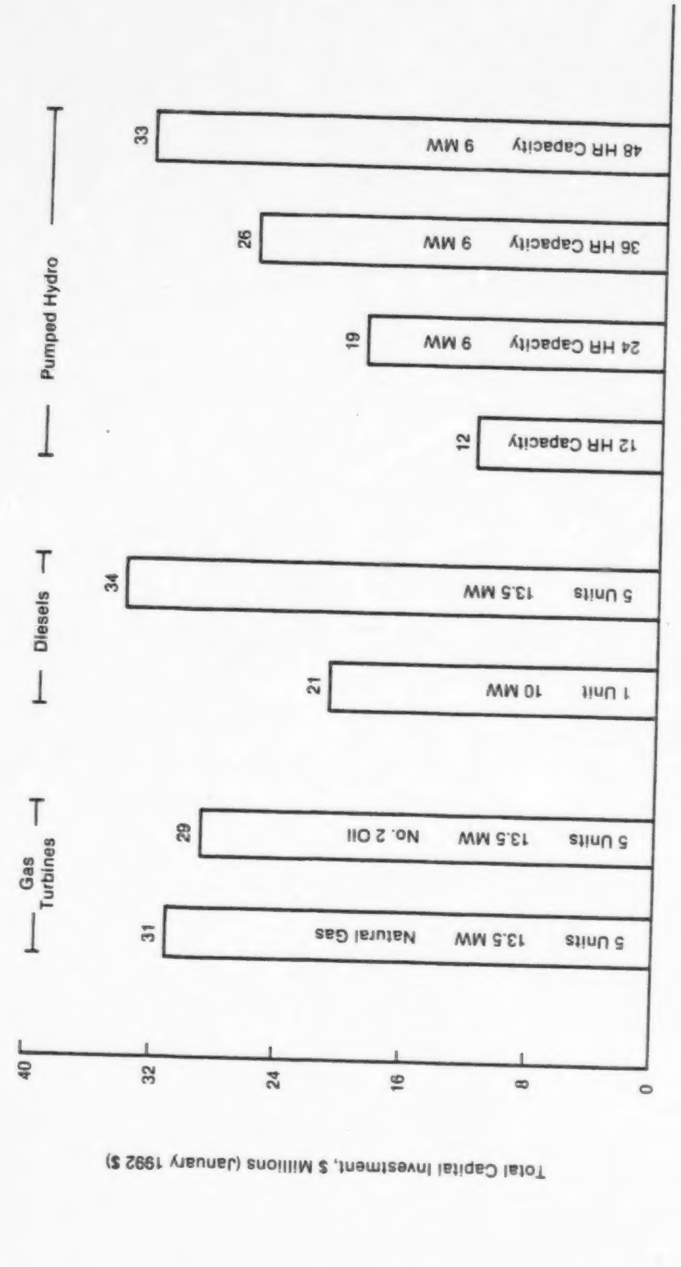

Figure 7-11. Critical launch demand power systems

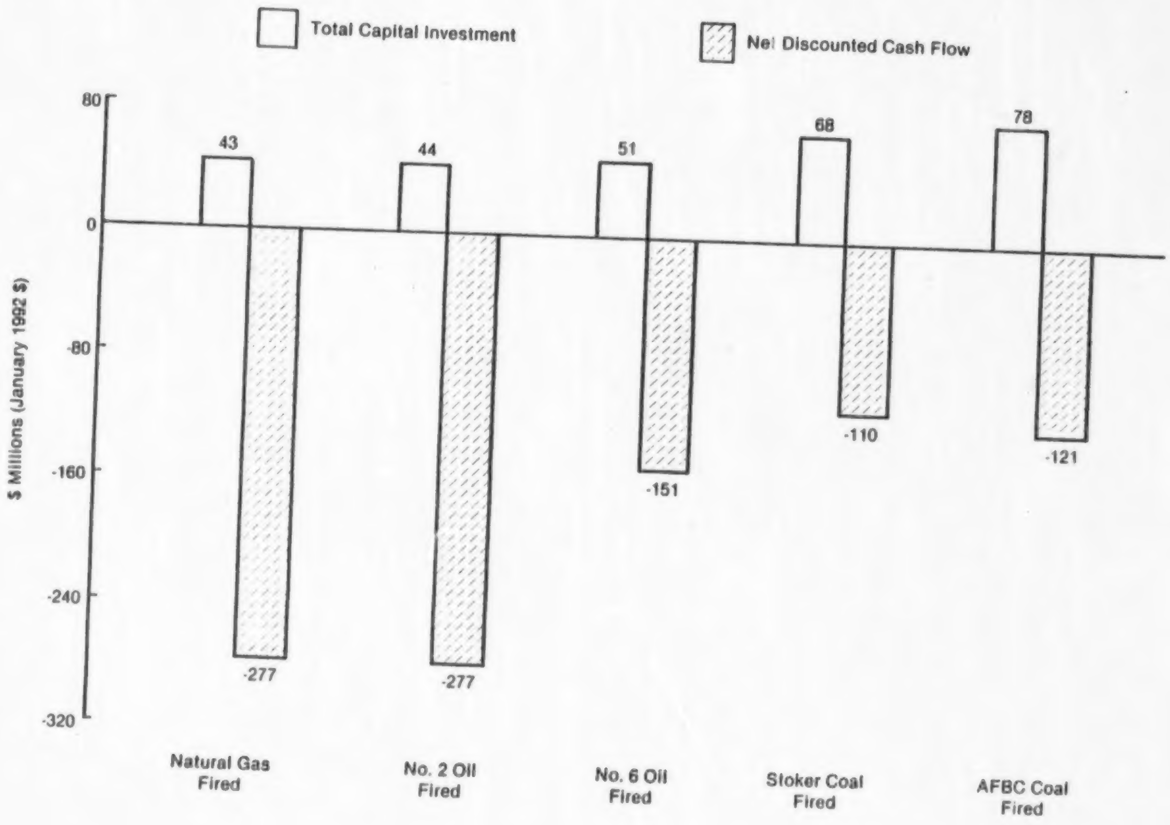

Figure 7-12. Continuous electricity production systems: 20 MW steam turbine technologies

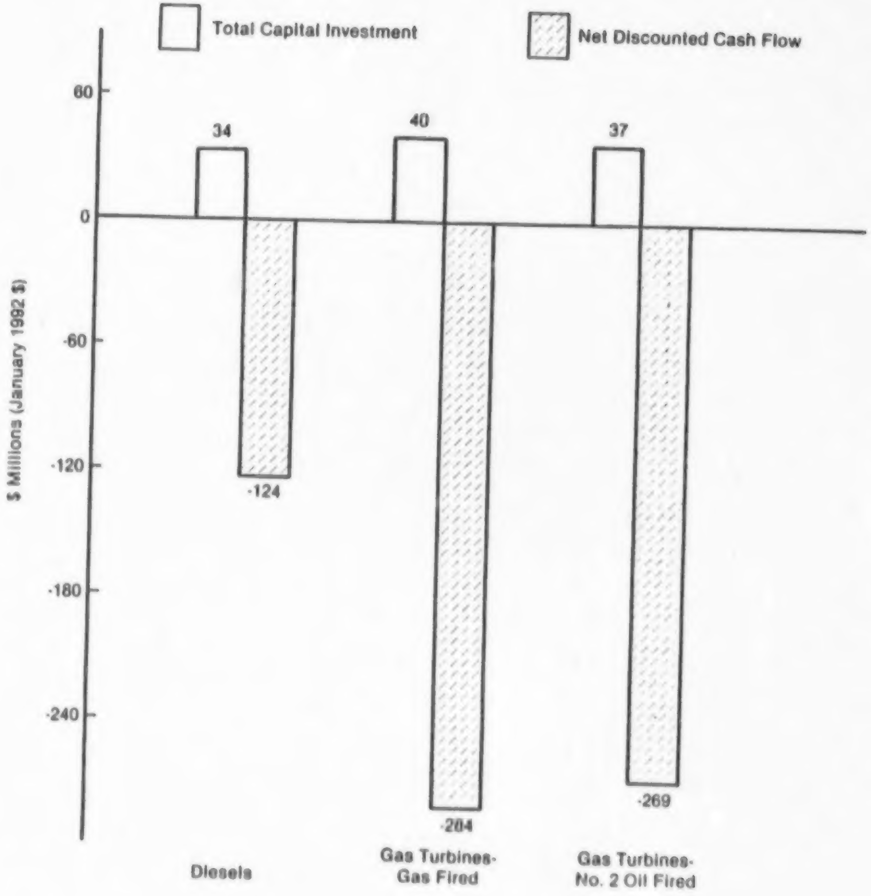

Figure 7-13. Continuous electricity production systems: 20 MW diesels and gas turbines

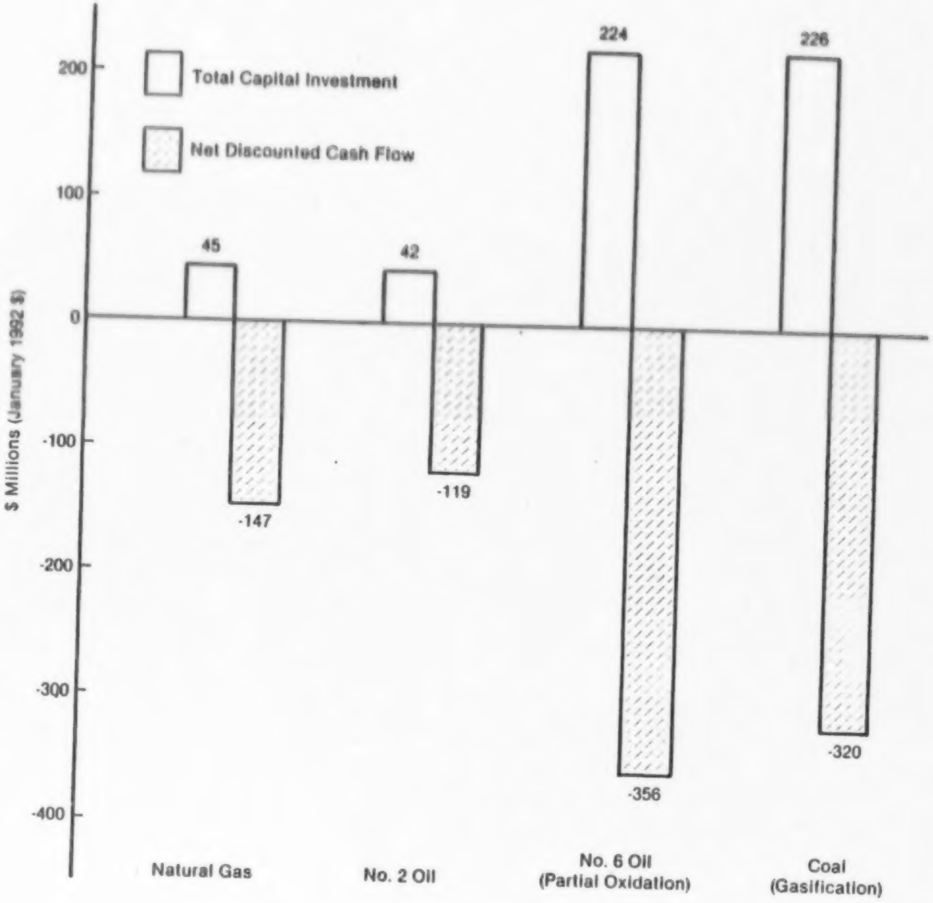

Figure 7-14. Continuous electricity production systems: 20 MW combined cycle technologies

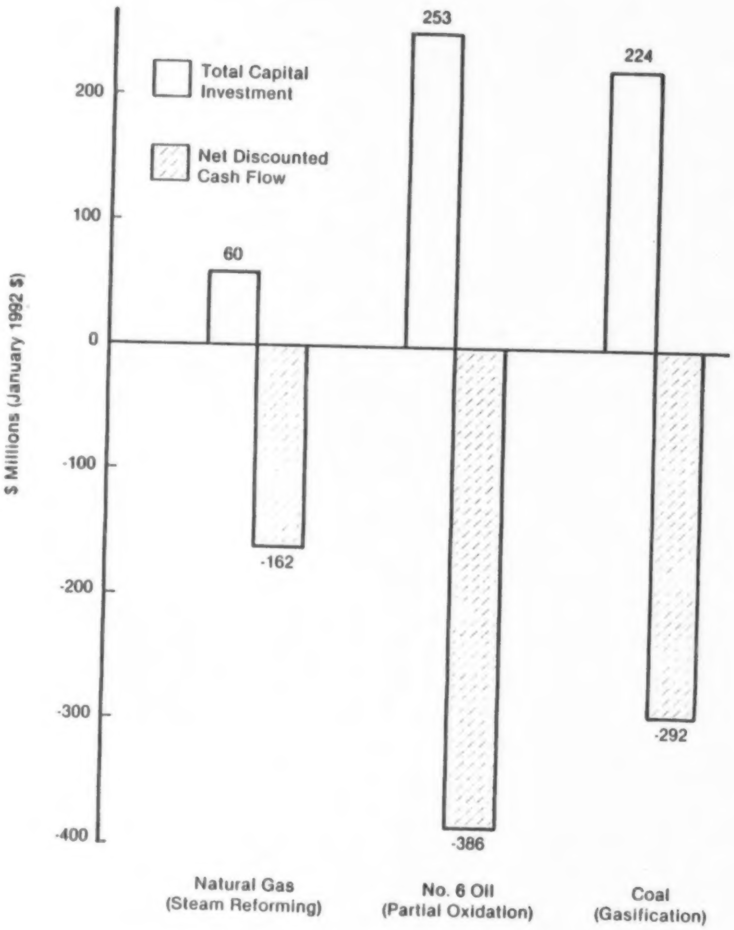

Figure 7-15. Continuous electricity production systems: 20 MW fuel cell technologies

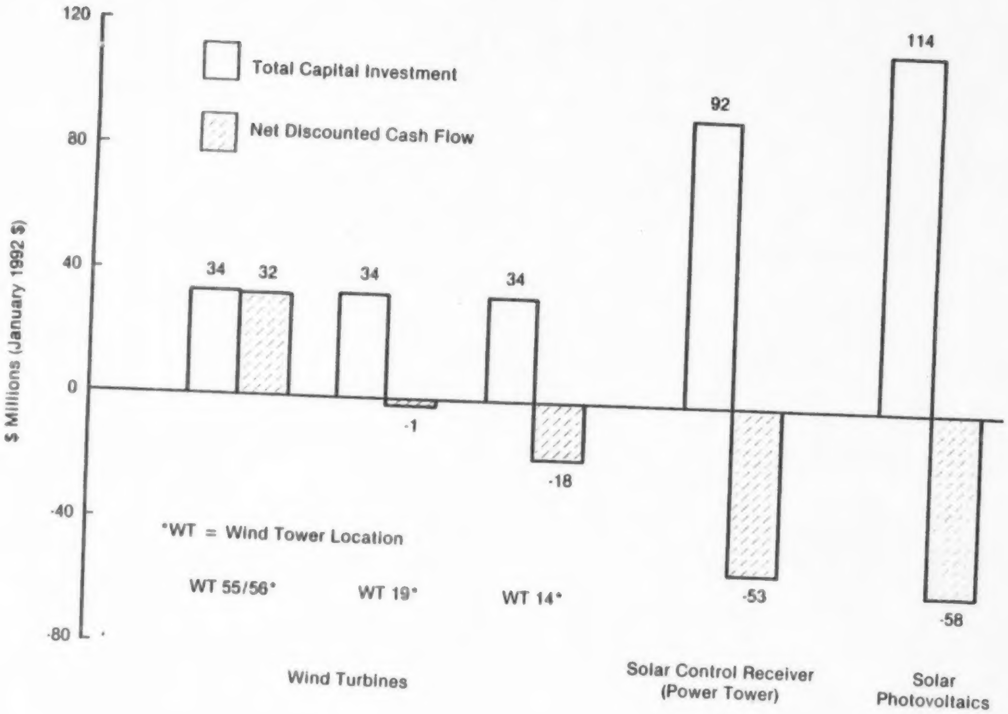

Figure 7-16. Continuous electricity production systems: 20 MW solar and wind technologies

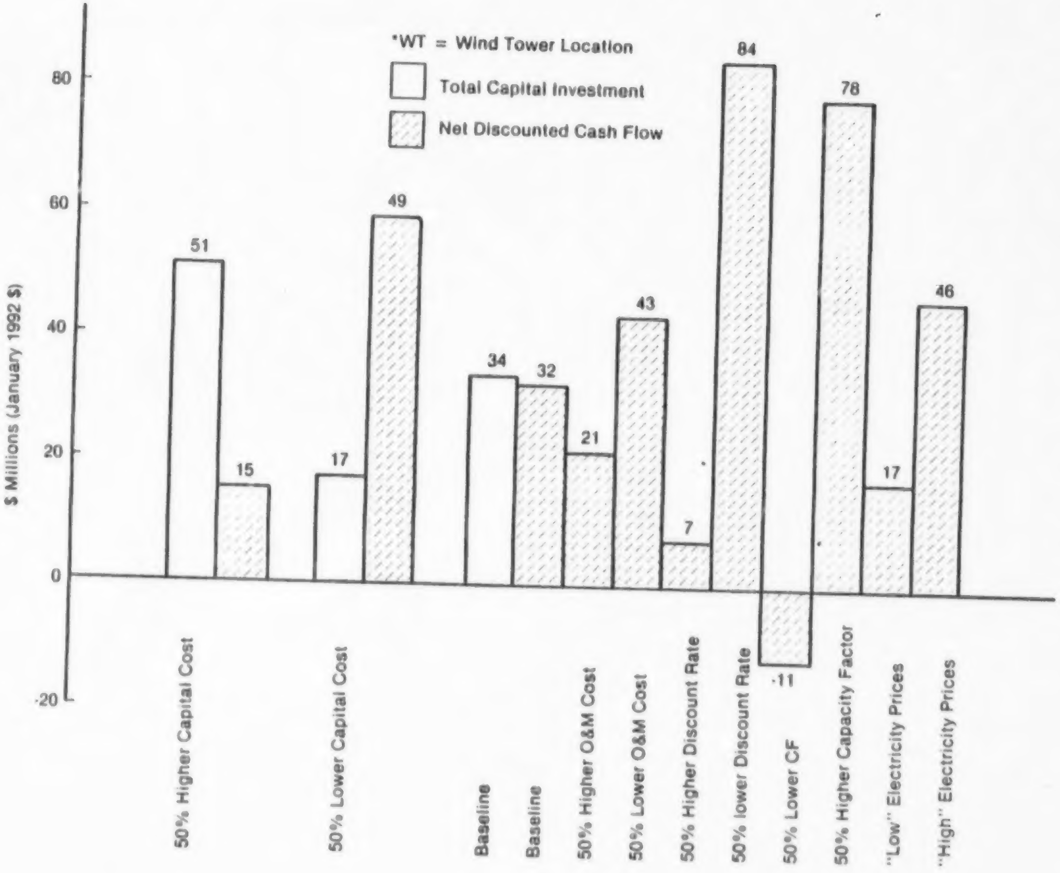

Figure 7-17. Continuous electricity production systems: selected sensitivity analysis of 20 MW wind turbines (WT 55/56*)

of solar and wind turbine technologies. And Figure 7-17 shows a selected sensitivity analysis of wind turbine systems.

The fossil fuel based systems described in Figures 7-12 through 7-15 all have highly negative net discounted cash flows and are thus not economically viable at VAFB. These systems are not economically viable due to their small size and consequently their low conversion efficiencies, and due to the relationships between fuel and electricity prices at VAFB. The relationships between fuel and electricity prices are especially important for systems based on natural gas or fuel oil, but are also important for systems which use coal. As shown below in Table 7-14 (based on prices from Section 5), because of relatively low growth in electricity prices, the fuel conversion efficiencies required to break even on fuel costs are very high, in many cases higher than achievable with the systems that have been considered in this study. Thus, based on fuel costs alone, all of the fossil fuels systems except coal systems are shown to be uneconomic. The position of coal systems is not promising since the break-even efficiencies are only slightly smaller than the actual system conversion efficiencies. And given the

TABLE 7-14. FUEL-TO-ELECTRICITY CONVERSION EFFICIENCIES REQUIRED TO BREAK-EVEN ON FUEL COSTS (%)

Year	Natural Gas	No.2 Fuel Oil	No.6 Fuel Oil	Coal
1983	37	31	21	14
1995	45	43	28	19
2010	53	51	33	24

relatively higher capital investment costs and non-fuel expenses of coal-based systems, they are also uneconomic at VAFB. Larger coal-fired systems (>100MW) typically achieve conversion efficiencies of 33-35 percent which could prove economic if the excess power is sold to the utility grid at avoided costs. No work was performed on this concept during this study. Note that although all of these fossil fuel based systems shown here are designed to also meet the requirements of critical launch power demands, systems not so designed, while lower in capital investment costs are also highly uneconomic at VAFB.

The two solar technologies, solar central receiver and solar photovoltaics, are also shown to be uneconomic at VAFB, but not as grossly uneconomic as estimated for the fossil fuel based systems. The costs of these systems are not yet well established; the baseline estimates shown here are the "average" of cost estimates for these technologies by 1992. If the capital investments were 50 percent lower than currently expected, the solar technologies would become economically viable alternatives. Note that neither these solar technologies nor wind turbine technologies are feasible for meeting the critical launch power demands.

Wind turbine systems are the only systems shown to be economically viable at VAFB but these systems can be economic only in selected areas around VAFB. As shown in Figure 7-16, wind turbines near existing wind tower locations 55 and 56 (located near Ridge Road in the south portion of VAFB) with average wind speeds of 18.5 mph @ 33 feet, will produce positive net discounted cash flows. The available data show that the average wind speeds near wind tower locations 55 and 56 are substantially higher than prevalent at most commercial wind turbine applications. These higher wind speeds generate more power per wind turbine, and are responsible for the positive economic results. The next best location at VAFB, near wind tower 19 (located in the southeastern portion of VAFB), with an average wind speed of 14.2 mph @ 33 feet, can be considered to break even. The next best location, near wind tower 14, with an average wind speed of about 12.3 mph @ 33 feet is not economic. Other wind tower locations at VAFB encounter milder winds and are clearly not economic.

The sensitivity analyses in Figure 7-17, for wind turbines at the best locations around VAFB, show that positive net discounted cash flows are expected over nearly all sensitivity areas. Only if the capacity factor were reduced by 50 percent would the overall economic analysis change.

(Note that the feasibility of installing a large number of wind turbines near wind towers 55 and 56 is not known and should be considered in any follow-up studies.)

7.3.2.3 Commodities Production Systems--The total capital investment and net discounted cash flows of commodities production systems are shown in Figure 7-18. Selected sensitivity analyses of air separation systems are shown in Figure 7-19.

If the current trends in LH_2 prices continue, that is, if the government continues to receive LH_2 at prices substantially below commercial LH_2 prices (due to excess supply), none of the on-site LH_2 production technologies are economically viable at VAFB. However, if the excess supply on the West Coast were eliminated due to expanded market demands or reduced supplies, and the government were required to pay commercial prices for LH_2, two technologies would become economically viable for producing LH_2 on-site. Natural gas steam reforming would be highly economic and electrolysis of water would be somewhat less economic for producing LH_2 on-site. Coal gasification and oil partial oxidation systems would not be economically viable, principally due to their high capital costs and relatively small plant sizes. Under the commercial LH_2 price premise, natural gas steam reforming and electrolysis systems would be economically viable at the lower shuttle launch rate of 7 per year, but would not be viable at a launch rate of 3 per year.

Air separation to produce LO_2, LN_2, and GN_2 is shown to have a positive net discounted cash flow at VAFB. And as shown by the sensitivity analyses in Figure 7-19, positive net discounted cash flows are expected over nearly all sensitivity areas. If the capital investment for air separation were

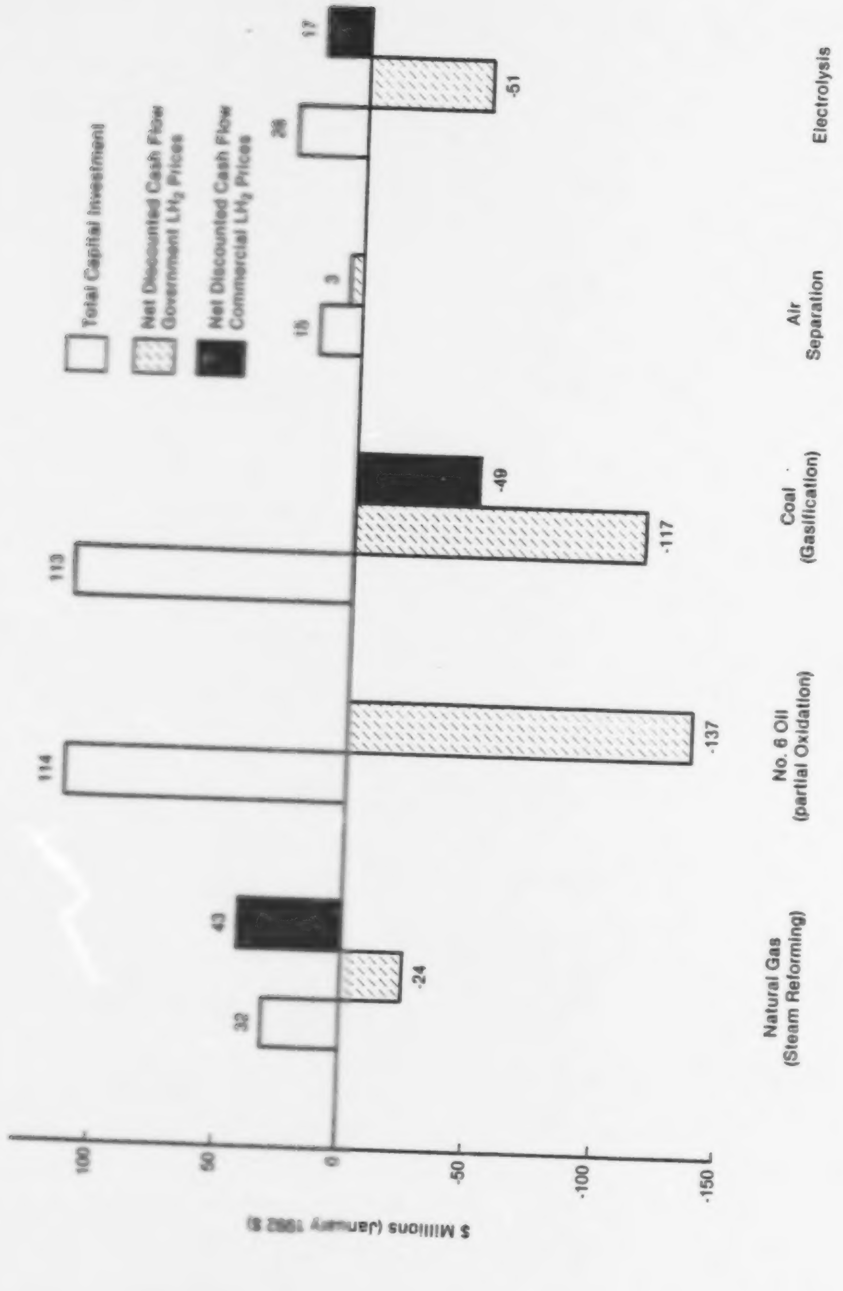

Figure 7-18. Commodities production systems: 10 launches per year

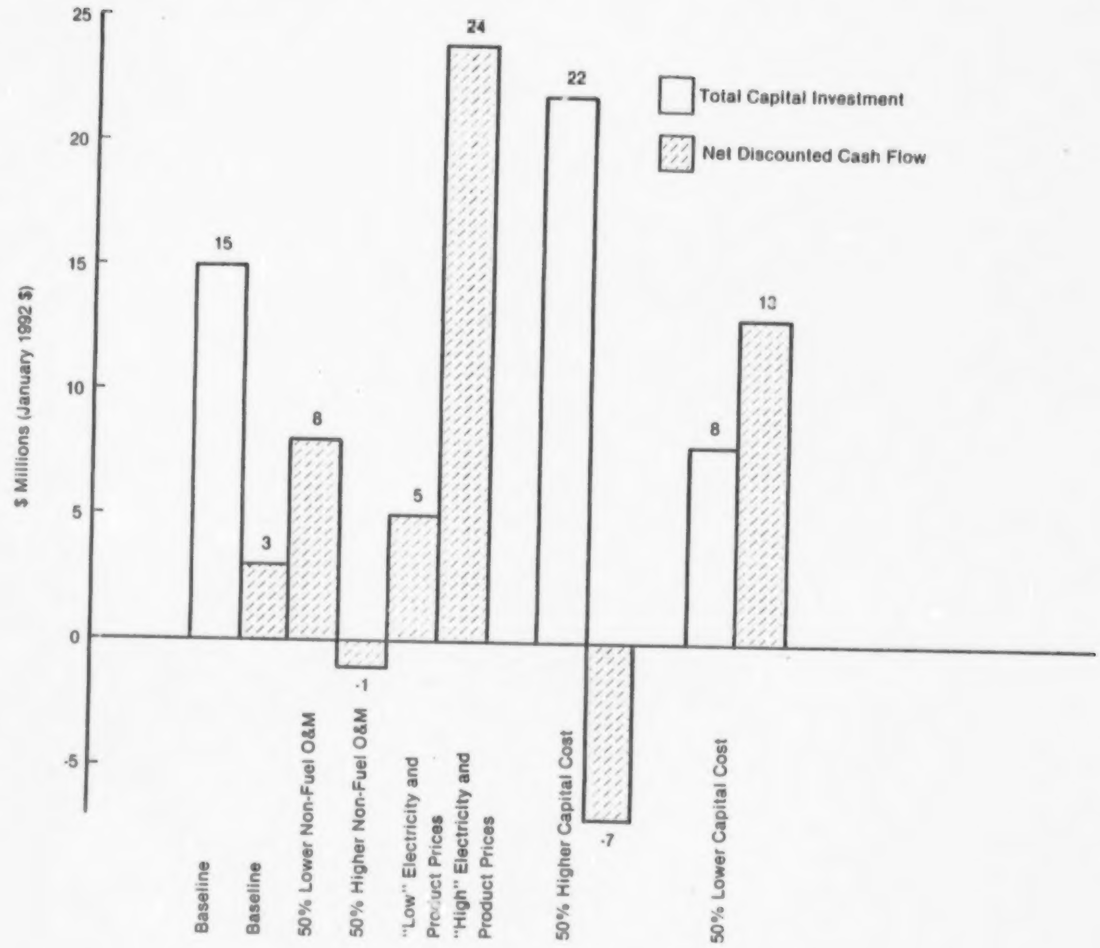

Figure 7-19. Commodities production systems: selected sensitivity analysis of air separation (10 launches per year)

increased by 50 percent, the net discounted cash flow would be negative. Also if non-fuel operating and maintenance expenses were 50 percent higher than expected, the net discounted cash flow would become slightly negative. Air separation plants smaller than 10 shuttle launches per year would be economic at VAFB because of the baseload requirements for GN_2, which do not vary with the shuttle launch rate.

7.3.2.4 Commodities and Electricity Production Systems--The total capital investment and net discounted cash flows of several polygeneration systems are shown in Figure 7-20.

Those systems which feature wind turbines in combination with air separation or electrolysis are shown to have very high positive net discounted cash flows. These results are attributable to the highly positive net discounted cash flows of the wind turbine systems located near wind towers 55 and 56.

The coal gasification polygeneration system in Figure 7-20 is conceptually the same as the polygeneration concept currently being evaluated for the Kennedy Space Center (KSC). This polygeneration concept is not economically viable at VAFB because of the very different circumstances of its possible application at VAFB. This polygeneration concept is not economically viable at VAFB mainly because:

- coal costs are relatively higher at VAFB
- electricity and LH_2 prices (or values for revenues) are much lower at VAFB
- polygeneration capacities are much smaller at VAFB
- relatively more electricity (less valuable than LH_2) would be produced at VAFB

(Also, note that the cost estimates in this study presume cost/design contingencies which add 25 percent to the capital investment estimate, whereas

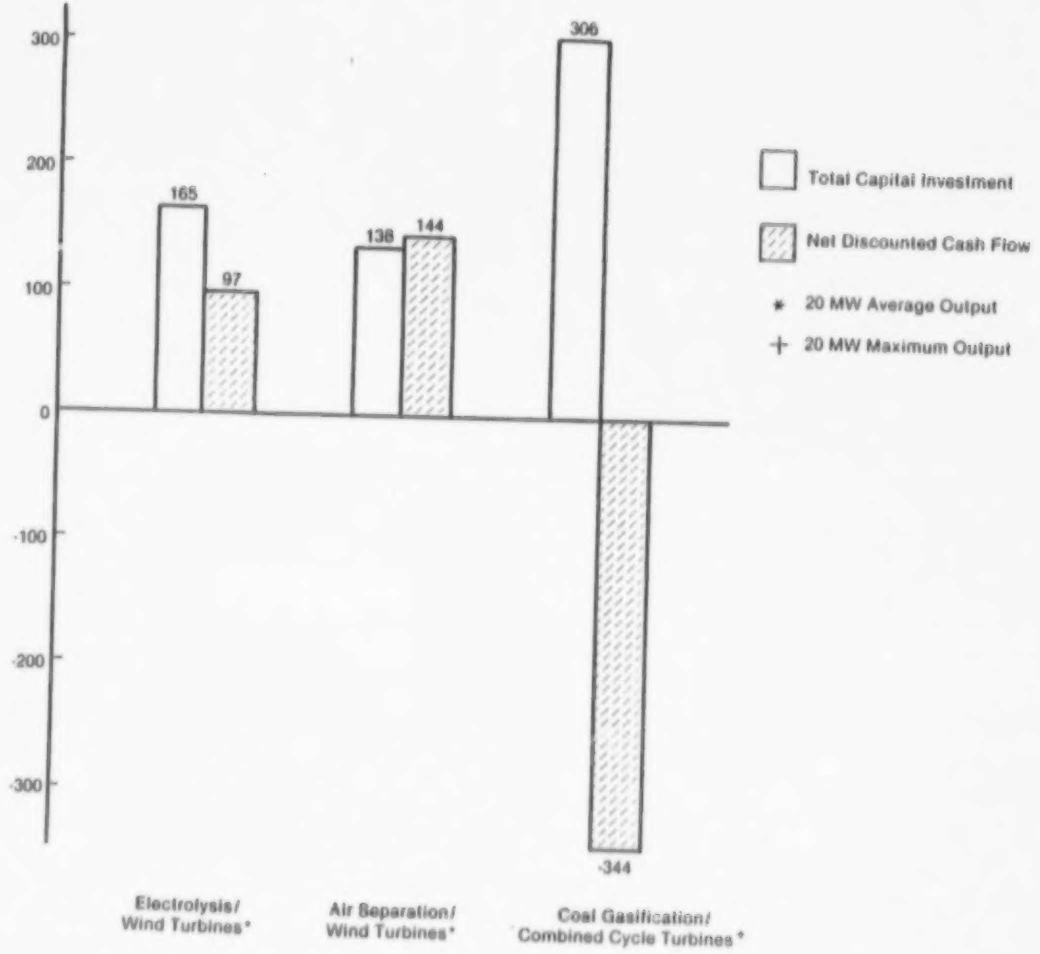

Figure 7-20. Commodities and electricity production systems: 10 launches per year and 20 MW*,+

the more detailed KSC studies presume lower, nominal contingencies.) The capacity factors presumed in this study are also somewhat less than those presumed in KSC studies.

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Section 8

OVERALL SYSTEM EVALUATION AND RANKING

This section presents an overall evaluation of the candidate production systems based on the technical and economic characterizations from Section 7. Based on the evaluation, ratings are developed to more simply compare the various systems. Based on the ratings, the most attractive systems for the continuous production of electricity and/or commodities are identified. The most attractive systems for supplying critical launch power demands are also identified.

8.1 OVERALL SYSTEM EVALUATION AND RATING

Table 8-1 summarizes the technical and economic characterizations from Section 7.

The evaluations in Table 8-1 are converted to ratings in Table 8-2 to allow a more straightforward comparison of the various production systems. Positive ratings in Table 8-2 obviously indicate positive factors in the four areas of evaluation. Specific definitions of the ratings in Table 8-2 are given in the footnotes to Table 8-2.

8.2 IDENTIFICATION OF MOST ATTRACTIVE SYSTEMS

The most attractive systems for the continuous production of electricity and/or commodities are identified in Table 8-3. The systems in Table 8-3 have at most only one negative or zero rating in the four areas of evaluation. All of the systems identified in Table 8-3 rate high in the technical, environmental, and reliability areas. The only negative ratings are in the economic areas, where photovoltaics are shown to have a negative net present value and

TABLE 8-1. OVERALL SYSTEM EVALUATION

System	Areas of Evaluation			
	Technical	Economic[1]	Environmental	Reliability[2]
ELECTRICITY PRODUCTION				
Boiler/Steam Turbine				
Natural gas	Well developed, widely applied	Very high negative NPV	Requires NO_x air emission offsets	Moderate
No. 2 fuel oil	Well developed, widely applied	Very high negative NPV	Requires NO_x air emission offsets; solid wastes could be classified as hazardous	Moderate
No. 6 fuel oil	Well developed, widely applied	High or very high negative NPV	Requires NO_x and possibly SO_2 air emission offsets; solid wastes could be classified as hazardous	Moderate
Stoker coal	Well developed, widely applied	High or very high negative NPV	Requires NO_x air emission offsets; solid wastes could be classified as hazardous	Moderate
AFBC coal	Well developed, becoming widely applied	High or very high negative NPV	Requires NO_x air emission offsets; solid wastes could be classified as hazardous	Moderate
Gas Turbine				
Natural gas	Well developed, widely applied	Very high negative NPV	Requires NO_x air emission offsets	Moderate
No. 2 fuel oil	Well developed, widely applied	Very high negative NPV	Requires NO_x and SO_2 air emission offsets	Moderate
Combined Cycle Turbine				
Natural gas	Well developed, widely applied	High or very high negative NPV	Requires NO_x air emission offsets	Moderate
No. 2 fuel oil	Well developed, widely applied	High or very high negative NPV	Requires NO_x and possibly SO_2 air emission offsets	Moderate
No. 6 fuel oil (via partial oxidation)	Well developed components, not commercially used in combination	Very high negative NPV	Requires NO_x air emission offsets; solid wastes could be classified as hazardous	Low
Coal (via gasification)	Components are either well developed or are currently being demonstrated, not commercially used	Very high negative NPV	Requires NO_x air emission offsets, solid wastes could be classified as hazardous	Low
Diesels	Well developed and widely applied	High or very high negative NPV	Requires particulate, NO_x, and SO_2 air emission offsets	High
Fuel Cells				
Natural gas (via steam reforming)	Most components are well developed but fuel cell components are currently being demonstrated; not commercially used in combination	High or very high negative NPV	Minor air emissions; small amount of solid wastes could be classified as hazardous	Moderate
No. 6 fuel oil (via partial oxidation)	Most components are well developed but fuel cell components are currently being demonstrated; not commercially used in combination	Very high negative NPV	Minor air emissions; solid wastes could be classified as hazardous	Low
Coal (via gasification)	Most components are well developed but gasification and fuel cell components are being demonstrated; not commercially used in combination	Very high negative NPV	Minor air emissions; solid wastes could be classified as hazardous	Low

(continued)

TABLE 8-1. (continued)

System	Areas of Evaluation			
	Technical	Economic[1]	Environmental	Reliability[2]
Wind Turbines	Small turbines (less than about 200 kW) are well developed and widely applied	High positive NPV at VAFB wind tower locations 55 and 56; marginal or high negative NPV at other wind tower locations	No air, water, or solid emissions	Moderate reliability but low capacity factor due to variability in winds
Solar Central Receiver (Power Tower)	Demonstration facility is operating but not commercially used	High negative NPV	No air, water, or solid emissions	High reliability but low capacity factor due to seasonal, daily, & weather variations
Solar Photovoltaics	Well developed; commercial plants exist; current R&D is aimed at cost reduction	High negative NPV based on mid-range expectations of costs; marginal positive NPV if capital costs are even more significantly lowered by R&D; current high capital costs would cause very high negative NPV	No air, water, or solid emissions	High reliability but low capacity factor due to seasonal and daily variations
Pumped Hydro	Well developed, widely applied	NPVs not determined because pumped hydro would be used only for supply of critical launch power demands; NPV cash flows other than capital not determined	No air, water, or solid emissions	High
COMMODITIES PRODUCTION				
Steam Reforming	Well developed, widely applied	High negative NPV under govt. LH_2 price trends; marginal to high positive NPV under commercial LH_2 price trends	Minor air emissions; small amounts of solid wastes could be classified as hazardous	High
Partial Oxidation	Well developed, widely applied	High to very high negative NPV	Minor air emissions; solid wastes could be classified as hazardous	Moderate
Coal Gasification	Currently being demonstrated	High to very high negative NPV under govt. LH_2 price trends; marginal to high negative NPV under commercial LH_2 price trends	Minor air emissions; solid wastes could be classified as hazardous	Low
Air Separation	Well developed and widely applied	Marginal positive NPV	No air, water, or solid emissions	High
Electrolysis	Well developed; commercial plants exist	High negative NPV under govt. LH_2 price trends; marginal to high positive NPV under commercial LH_2 price trends except at 3 LPY plant size	No air, water, or solid emissions	High
Coal Gasification/ Air Separation	Components are either well developed or are being demonstrated; not commercially used	Very high negative NPV	Minor air emissions; solid wastes could be classified as hazardous	High for air separation, low for gasification

(continued)

TABLE 8-1. (continued)

System	Areas of Evaluation			
	Technical	Economic[1]	Environmental	Reliability[2]
COMMODITIES AND ELECTRICITY PRODUCTION				
Wind Turbines/ Electrolysis	Well developed components; not demonstrated as combined system; backup power is required	High to very high positive NPV except at 3 LPY plant size	No air, water or solid emissions	High for electrolysis, moderate for wind turbines; low capacit factor for wind
Wind Turbines/ Air Separation	Well developed components; not demonstrated as combined system; backup power is required	High to very high positive NPV	No air, water, or solid emissions	High for air separation, moderate for wind turbines; low capacity factor for wind turbines
Coal Gasification/ Combined Cycle Turbine	Components are either well developed or currently being demonstrated; not commercially used in combination	Very high negative NPV	Requires NO_x air emission offsets; solid wastes could be classified as hazardous	Low

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[1] Economic evaluations are based on the sum or net present value (NPV) of all project cash flows, in January 1992 dollars. Negative values indicate that the project is uneconomic. Zero values of the NPV indicate that the project benefits (or positive cash flows) exactly balance the project negative cash flows (such as initial investment); this balance of positive and negative cash flows will change with different assumptions about economic performance measures such as the discount rate. Positive values of the NPV indicate that the project is economic at the presumed discount rate. Generally, projects with the highest positive values of the NPV will be preferred. In this summary table, the following relative terms are used to describe the economic result of evaluation; the definitions of these terms is arbitrary:

very high - more than $100 million

high - less than or equal to $100 million but more than $10 million

marginal - less than or equal to $10 million but more than zero

[2] Reliability evaluation measures are defined as follows:

high - more than or equal to 92.5 percent

moderate - more than or equal to 87.5 percent

low - less than 87.5 percent

TABLE 8-2. OVERALL SYSTEM RATINGS

System	Areas of Evaluation[1]			
	Technical[2]	Economic[3]	Environmental[4]	Reliability[5]
ELECTRICITY PRODUCTION				
Boiler/Steam Turbine				
Natural gas	+	--	--	0
No. 2 fuel oil	+	--	--	0
No. 6 fuel oil	+	--	--	0
Stoker coal	+	--	--	0
AFBC coal	+	--	--	0
Gas Turbine				
Natural gas	+	--	--	0
No. 2 fuel oil	+	--	--	0
Combined Cycle Turbine				
Natural gas	+	--	--	0
No. 2 fuel oil	+	--	--	0
No. 6 fuel oil (via partial oxidation)	0	--	--	--
Coal (via gasification)	--	--	--	--
Diesels	+	--	--	+
Fuel Cells				
Natural gas (via steam reforming)	--	--	+	0
No. 6 fuel oil (via partial oxidation	--	--	--	--
Coal (via gasification)	--	--	--	--
Wind Turbines	+	+	+	0

(continued)

TABLE 8-2. (continued)

System	Areas of Evaluation			
	Technical[1]	Economic[2]	Environmental[3]	Reliability[4]
Solar Central Receiver	0	--	+	+
Solar Photovoltaics	+	--	+	+
Pumped Hydro	+		+	+
COMMODITIES PRODUCTION				
Steam Reforming	+	-/+[5]	+	+
Oil Partial Oxidation	+	--	--	0
Coal Gasification	--	--	--	--
Air Separation	+	+	+	+
Electrolysis	+	-/+[5]	+	+
Coal Gasification/Air Separation	--	--	--	--
COMMODITIES AND ELECTRICITY PRODUCTION				
Wind Turbines/Electrolysis	0	+	+	0/+[6]
Wind Turbines/Air Separation	0	+	+	0/+[6]
Coal Gasification/Combined Cycle Turbine	--	--	--	--

---

[1] "+" denotes well developed, widely applied systems in all areas; "0" denotes systems whose components are well developed but commercial applications are few or do not exist; "--" denotes systems with one or more components still in demonstration

[2] "+" denotes positive net present value (NPV); "0" denotes zero or marginal NPV; "--" denotes negative NPV.

[3] "+" denotes inherently clean system or system with minor emissions; "--" denotes system which generates hazardous wastes and/or requires air emission offsets

[4] "+" denotes high single-unit reliability (∿95%); "0" denotes moderate single-unit reliability (∿90%); "--" denotes low single-unit reliability (∿85%).

[5] "-/+": "--" under government LH_2 price trends, "+" under commercial LH_2 price trends.

[6] 0/+: "0" for wind turbines, "+" for electrolysis or air separation.

TABLE 8-3. MOST ATTRACTIVE SYSTEMS FOR CONTINUOUS PRODUCTION OF ELECTRICITY AND/OR COMMODITIES[1]

System	Areas of Evaluation			
	Technical[2]	Economic[3]	Environmental[4]	Reliability[5]
ELECTRICITY PRODUCTION				
Wind Turbines	+	+	+	0
Solar Photovoltaics	+	--	+	+
COMMODITIES PRODUCTION				
Steam Reforming	+	-/+[6]	+	+
Air Separation	+	+	+	+
Electrolysis	+	-/+[6]	+	+
COMMODITIES AND ELECTRICITY PRODUCTION				
Wind Turbines/Electrolysis	0	+	+	0/+[7]
Wind Turbines/Air Separation	0	+	+	0/+[7]

[1] Systems shown here are those systems from Table 2-1 which have at most only one negative or zero rating in the four areas of evaluation.

[2] "+" denotes well developed, widely applied systems in all areas; "0" denotes systems whose components are well developed but commercial applications are few or do not exist; "--" denotes systems with one or more components still in demonstration.

[3] "+" denotes positive net present value (NPV); "0" denotes zero or marginal NPV; "--" denotes negative NPV.

[4] "+" denotes inherently clean system or system with minor emissions; "--" denotes system which generates hazardous wastes and/or requires air emission offsets.

[5] "+" denotes high single-unit reliability (∿95%); "0" denotes moderate single-unit reliability (∿90%); "--" denotes low single-unit reliability (∿85%).

[6] "-" under government LH_2 price trends, "+" under commercial LH_2 price trends.

[7] 0/+: "0" for wind turbines, "+" for electrolysis or air separation.

steam reforming and electrolysis are shown to have negative net present values under the current trends in government LH_2 prices.

The most attractive system for supplying critical launch power demands are identified in Table 8-4.

TABLE 8-4. MOST ATTRACTIVE SYSTEMS FOR SUPPLYING CRITICAL LAUNCH POWER DEMAND

System	Areas of Evaluation[1]			
	Technical[2]	Economic[3]	Environmental[4]	Reliability[5]
Gas Turbine				
Natural Gas	+	0	--	0
No. 2 fuel oil	+	0	--	0
Diesel Engines	+	0	--	+
Pumped Hydro	+	+	+	0

---

[1] Systems shown here have lower capital costs than alternative systems such as gas-fired boiler/turbines. Positive ratings obviously indicate positive factors while zero ratings indicate neutral factors and negative ratings indicate negative factors.

[2] "+" denotes well developed, widely applied systems in all areas.

[3] For systems supplying critical launch power demands only, the most important economic parameter is the total capital investment; because of their short hours of operation, operational costs are of lesser importance. The relative ranking of these systems varies with the set of design bases. Depending on these bases, each of these systems is potentially the system of choice based on the lowest capital investment. Pumped hydro storage systems are the lowest cost options unless more than 24 hours of pumped hydro storage capacity are needed. (Twenty-four hours of storage is about twice the 11-hour duration of critical launch demands.) The gas turbine systems would be the least expensive of the four options if: 1) pumped hydro alternatives were required to have capacities greater than 24 to 36 hours (which corresponds to twice or thrice the critical launch demand period of about 11 hours), and 2) diesel engine alternatives required multiple units to achieve the 95% reliability criterion. Based on a preliminary analysis, new diesel engines may be more reliable than gas turbines and thus could meet the 95% reliability criterion with single units. But if multiple diesel units were required, equivalent gas turbine systems would be less expensive. Pumped hydro systems would be less expensive than single diesels unless more than about 24 hours of pumped hydro storage capacity were needed.

[4] "+" denotes inherently clean system or system with minor emissions. "--" denotes system which generates hazardous wastes and/or requires air emission offsets.

[5] "+" denotes high single-unit reliability (~95%). "0" denotes moderate single-unit reliability (~90%).

APPENDIX A

BACKGROUND INFORMATION
ON INDIVIDUAL TECHNOLOGIES

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A.1 Technology: Atmospheric Fluidized Bed Combustion (AFBC) Boiler/Steam Turbine.

Fuels: Coal (also biomass, natural gas, process wastes)

Status: Research and development on atmospheric fluidized bed combustion (AFBC) was started in England in the 1950's and in the U.S. in the mid-1960's. The first commercial unit in the U.S. began operation in late 1973, but the majority of the existing and planned units have commercial service dates of 1979 or later.

There are currently over 150 AFBC units either in operation or planned for startup by 1985. Table A.1-1 contains a partial summary of these units. AFBC boilers are offered by at least 36 manufacturers, 20 of which are in the U.S. (A.1-1). Table A.1-2 lists the manufacturers and their equipment specifications. The technology has been proven reliable, and is capable of reducing NO_x and SO_2 emissions to the levels required by federal environmental regulations (A.1-1, A.1-2, A.1-3, A.1-4).

Description: Coal and limestone are transported to the boiler site by rail or truck and stored. After crushing and screening, the coal and limestone are fed into a bed of fluidized particles. The bed consists of coal, unreacted and reacted limestone, and ash suspended in a stream of combustion air blowing upwards through a perforated air distributor plate located at the base of the bed. Ash and reacted and unreacted limestone are continuously removed from the bed to maintain the proper bed depth. The flue gas and entrained particles are passed through a cyclone where the solid particles are removed for recycle. The flue gas is then passed through an additional cyclone and a fabric filter or electrostatic precipitator for final particulate removal.

Energy recovery is accomplished by heat transfer surfaces located in the combustion bed and downstream in the path of the combustion products. The steam produced can be used directly or in a turbine-generator for the production of electricity.

TABLE A.1-1. SUMMARY OF LARGER AFBC BOILERS EXISTING AND PLANNED

Plant Owner	Location	MW(e)[1]	Steam Data Capacity 1000 lb/hr	Steam Data Pressure psig	Steam Data Temperature °F	Design Fuels	Commercial Service Date
Atlas Consol. Mining & Dev. Corp.	Cebu, Phillipines	51[2]	352	914	905	L	1982
Ashland Petroleum Co.	Cattlesburg, KY	38[2]	325	450	700	CO, Ng	2/83
Elektrizitatswerk Wesertal GmbH	Hameln, W. Germany	47	309	1741	986	C	1983
Monangahela Power Co.	Rivesville, W. VA	43	300	1350	925	C	10/76
Saarbergwerke AG	Volklingen, W. Germany	80[2]	27[3]	-[3]	-[3]	C	1982
A Ahlstrom Oy	Kauttua, Finland	30	200	120	930	Pt, C	4/81
National Coal Board	Grimethrope, England	24	176	435	824	C	1980
ENEL[4]	Porto Vesune, Italy	25	175	840	890	C	1984
Kemira Oy	Oulu, Finland	27	155	1275	960	Pt, C	1/83
Zellstoff-und Papierfabrick AG	Frantschach, Austria	24	154	1215	970	W, BC	11/83
Northern States Power Co.	LaCrosse, Wisconsin	19	150	450	750	W	12/81
Hylte Bruks AB	Hyltebruk, Sweden	19	143	925	840	Pt, W, C	8/82
Tennessee Valley Authority	Paducah, KY	18	120	2400	1000	C	6/82
Shell Nederland Raffinaderij BV	Pirnus, Holland	16	110	1174	923	C	7/82
Ruhrkohle AG	Dusseldorf, W. Germany	14	109	247	752	C	1979

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[1] Rating calculated by converting steam from stated conditions to 80% quality steam at 1.0 psig and 101°F and applying a 77% efficiency factor.

[2] Two units installed. ed boiler.

[3] Rating is in million Btu/hr; hot combustion gas exiting fluidized bed combustor flows to a conventional fired boiler.

[4] Ente Nazionale per l'Energia Elettrica

Abbreviations:
BC = Brown coal
C = Coal
CO = Carbon monoxide
L = Lignite
Ng = Natural gas
Pt = Peat
W = Wood, woodwaste

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TABLE A.1-2. COMMERCIAL AVAILABILITY OF AFBC UNITS

Company Address	AFBC Boiler Technology		Watertube or Firetube Boiler	Types of FBC Systems Offered	Boiler Capabilities Commercially Available				Number of Units Installed	
	Built Under License	Licensing Company			Capacity 1000 lb/hr	Pressure psig	Temperature °F	Fuel(s)	USA	Total
A. Ahlstrom Oy P.O. Box 329 SF-00101 Helsinki 10, Finland	No	-	Wt	Fx, Fcb	20-400	140-2500	350-1000	-[1]	0	9
Ansaldo SpA Viale Sarca, 336 Milano 20126, Italy	No	-	Wt	Fx	Up to 400	NAv	Up to 1000	Coal, wood-	1	0
Babcock & Wilcox Co. 20 S. Van Buren Ave. Barberton, Ohio 44203	No	-	Wt	Fx	More than 50	150-2400	Up to 1050	-[1,2]	2	2
Babcock Hitachi KK 6-2, 2-chome, Ote-machi Chiyodo-Ku, Tokyo 100, Japan	No	-	Wt	Fx	22-1100	100-2400	Up to 1050	-[1]	0	3
C-E Natco 5330 E. 31st St. Tulsa, Okla. 74135	Yes	Energy Resources Co.	-[3]	-[3]	-[3]	-[3]	-[3]	-[3]	1[11]	1[11]
C-E Power Systems 1000 Prospect Hill Rd. Windsor, Ct. 06095	No	-	Wt	Fx, Fcb	50-500	100-1800	330-950	-[1]	1	1
Combustion Systems Ltd. BP Research Centre Sunbury-on-Thames, Middlesex England TW16 7LN	No	-	Wt, Ft[4]	Fx[4]	25-500[4]	1000-2400[4]	Up to 1005[4]	-[1]	0	0
Curtiss-Wright Corp. One Passaic St. Wood-Ridge, N.J. 07075	No	-	Wt	Fx	20-125	100-800	250-825	Coal, wood-waste, biomass	1[12]	1[12]
Danks of Netherton, Ltd. Halesowen Rd, Netherton Dudley, West Midlands England DY2 9PG	Yes	Combustion Systems Ltd.	Wt, Ft	Fx	15-70	100-900	Up to 900	-[1]	0	4
Deborah Fluidised Combustion, Ltd. 6 Davy Dr. NW Industrial Estate Peterlee, Durham, England	No	-	Wt	Fcb	1-50	100-900	-[5]	-[1]	1	12

(continued)

TABLE A.1-2. (Continued)

Company Address	AFBC Boiler Technology		Watertube or Firetube Boiler	Types of FBC Systems Offered	Boiler Capabilities Commercially Available				Number of Units Installed	
	Built Under License	Licensing Company			Capacity 1000 lb/hr	Pressure psig	Temperature °F	Fuel(s)	USA	Total
Dedert Corp. Thermal Processes Div. 20000 Governors Dr. Olympia Fields, Ill. 60461	No	-	Wt, Ft	Fx	5-125	10-900	212-825	-[1]	2	2
Deutsche Babcock Werke AG Duisburger Strasse 375 Oberhausen D-4200, W. Germany	No	-	Wt	Fx, Pcb	20-700	145-2600	360-1100	-[1]	0	14
Dorr-Oliver Inc. 77 Havemeyer Lane Stanford, Ct. 06904	No	-	Wt	Fx, Pcb	40-250	Up to 800	Up to 750	-[1]	1[13]	1[13]
Energy Products of Idaho 4006 Industrial Ave. Coeur d'Alene, Idaho 83814	No	-	Wt, Ft	Fx	10-250	15-1000	250-900	-[1]	18	22
Energy Resources Co. One Alewife Place Cambridge, Mass. 02140	No	-	Wt, Ft	Fx	10-250	Up to 1500	Up to 850	-[1]	2	2
Fluidised Combustion Contractors Ltd. 11 The Boulevard Crawley, Sussex England RH10 1UX	Yes	Solids Circulation Systems, Inc.[10]	Wt, Ft	Fx, Pcb, Fcb	-[3]	-[3]	-[3]	-[1]	1	2
Fluidyne Engineering Corp. 3900 Olson Memorial Hwy. Minneapolis, Minn. 55422	No	-	Wt	Fx	7-50	15-650	Up to 750	-[1]	1	1
Foster Wheeler Boiler Corp. 110 S. Orange Ave. Livingston, N.J. 07039	Yes	Solids Circulation Systems, Inc.	Wt	Fx, Fcb	40-600	150-2400	Up to 1050	-[1]	8	11
Foster Wheeler Power Products Ltd. Greater London House Hampstead Rd., London England NW1 7QN	Yes	-[6]	Wt	Fx, Fcb	30-600	200-2000	200-1000	-[1]	0	2
Generator Industri AB P.O. Box 95 S-433 22 Partille, Sweden	Yes	Fluidized Combustion Co.	Wt	Fx, Fcb	17-170	150-1000	Up to 800	Coal, woodwaste, biomass	0	8

(continued)

TABLE A.1-2. (Continued)

Company Address	AFBC Boiler Technology Built Under License	 Licensing Company	Watertube or Firetube Boiler	Types of FBC Systems Offered	Boiler Capabilities Commercially Available Capacity 1000 lb/hr	 Pressure psig	 Temperature °F	 Fuel(s)	Number of Units Installed USA	 Total
E. Green & Son Ltd. Wakefield England WF1 5PF	No	-	Wt	Fx	20-80	150-900	Up to 900	-[1]	1	1
International Boiler Works Co. 36 Birch St. E. Stroudsburg, Pa. 18301	No	-	Wt	Fx, Fcb	2-100	15-700	250-650	-[1]	4	4
Ishikawajima-Harima Heavy Industries Co., Ltd. 30-13 5-chome, Toyo Koto-ku, Tokyo 135, Japan	Yes	Fluidized Combustion Co.	Wt, Ft	Fx	-[3]	-[3]	-[3]	-[1]	0	2
Johnston Boiler Co. 300 Pine St. Ferrysburg, Mich. 49409	Yes	Combustion Systems Ltd.	Wt, Ft	Fcb	25-70	15-860	Up to 750	-[1]	19	29
E. Keeler Co. 238 West St. Williamsport, Pa. 17701	No	-	Wt	Fx	40-200	100-800	Up to 800	-[1]	1	1
ME Boilers Ltd. ME House, Fengate Peterborough, Cambs. England PE1 5BQ	Yes	Combustion Systems Ltd.	Wt	Fx	20-100	Up to 2500	Up to 900	-[1]	0	1
NEI Cochran Ltd. Newbie Works Annan, Dumfriesshire Scotland DG12 5QU	No	-	Ft	Fx	2-36	100-250	Sat	-[1]	0	6
Pyropower Corp.[7] P.O. Box 81608 San Diego, Calif. 92041	No	-	Wt	Fcb	50-400	200-2500	Up to 950	-[1]	1	1
Riley Stoker Corp. 9 Neponset St. Worcester, Mass. 01606	Yes	Fluidized Combustion Contractors Ltd.	Wt	Fx	More than 40	150-2600	Up to 1005	-[1]	0	0
Solids Circulation Systems, Inc. P.O. Box 2325 Boston, Mass. 02107	No	-	Wt	Fcb	20-200	150-1800	Up to 850	-[1]	0	0

(continued)

TABLE A.1-2. (Continued)

Company Address	AFBC Boiler Technology: Built Under License	AFBC Boiler Technology: Licensing Company	Watertube or Firetube Boiler	Types of FBC Systems Offered	Boiler Capabilities Commercially Available: Capacity 1000 lb/hr	Boiler Capabilities Commercially Available: Pressure psig	Boiler Capabilities Commercially Available: Temperature °F	Boiler Capabilities Commercially Available: Fuel(s)	Number of Units Installed: USA	Number of Units Installed: Total
Struthers Wells Corp. 1103 Pennsylvania Ave. W Warren, Pa. 16365	Yes	Battelle Memorial Institute	Wt	Fcb[8]	50-250	Up to 2650	Up to 900	Coal, petroleum, coke, lignite	2	2
Sulzer Brothers Inc. 200 Park Ave. New York, N.Y. 10017	No	-	Wt	Fx	20-100	145-1450	350-977	Coal	0	1
Tampella Ltd., Boiler Div. P.O. Box 626 SF-33101 Tampere 10, Finland	No	-	Wt	Fx	13-225	400-1800	Up to 1000	-[1]	0	6
Wallsend Slipway Engineers Ltd. Point Pleasant Wallsend, Tyne & Wear England NE28 6QN	No	-	Ft	Fx	5.3-59.8	150-250	Sat	-[1]	0	0
Wormser Engineering Inc. 225 Merrimac St. Woburn, Mass. 01888	No	-	Wt	Fx[9]	10-100	15-1000	Up to 750	-[1]	2	2
York-Shipley, Inc. P.O. Box 349 York, Pa. 17403	No	-	Ft	Fx	3-90	15-300	250-421	Coal, woodwaste, biomass	12	12

Footnotes:

1. Designed to burn the following fuels separately or in combination: coal, woodwaste, biomass, liquid wastes or sludges, coal-washing wastes.
2. Combination firing has limitations depending on the type of fuel burned.
3. Designed to meet customer requirements.
4. Range of equipment specifications offered.
5. Temperature depends on customer requirements.
6. Foster Wheeler Power Products Ltd. licenses the fluidized-bed technology for some of the equipment it offers from Fluidised Combustion Co., a joint venture of Foster Wheeler Development Corp. and Pope Combustion Systems Inc., and from Battelle Memorial Institute.
7. Pyropower is jointly owned by A Alhstrom Oy (Finland) and General Atomic (U.S.)
8. Combustor includes a dense bed section to enhance reactivity.
9. Multistage fluidized bed.
10. Fluidised Combustion Contracts Ltd. offers fluidized-bed combustion systems of its own design as well.
11. In conjunction with Energy Resources Co.
12. In conjunction with E. Keeler Co. and Dorr-Oliver Inc.
13. In conjunction with E. Keeler Co. and Curtiss-Wright Corp.
14. Approximately 88,000 lb/hr of 800 psig stream at 600°F will provide 7.5 MWe if used in power plant Rankine cycle.

Abbreviations:

Fcb--Full circulating bed
Ft--Firetube boiler
Fx--Fixed (bubbling) bed
NAv--Not available
Pcb--Partial circulating bed
Sat--Saturation temperature
Wt--Watertube boiler

The AFBC system described above, illustrated in Figure A.1-1, is the traditional fixed bed method. Several different configurations are available. These include the circulating bed AFBC (A.1-5, A.1-6, A.1-7, A.1-11), the staged bed AFBC (A.1-8), and the staged combustion AFBC (A.1-9). These second-generation AFBC units show improved ability to reduce emissions and increase combustion efficiency. Current coal-to-steam efficiency is about 80 percent. Second-generation units are commercially available.

Environmental Impact: AFBC technology has been proven capable of reducing SO_2, NO_x, and particulate emissions to levels required by federal new source performance standards.

Limestone addition controls SO_2 emissions. The calcium in the limestone reacts with SO_2 to form a solid sulfate. This eliminates the need for downstream flue gas desulfurization equipment. The amount of SO_2 removal is controlled by several factors. The most important of these is the Ca/S ratio. High Ca/S ratios provide high SO_2 removal, but they also increase the amount of solid wastes requiring disposal. The second generation AFBC units achieve the same level of SO_2 removal with lower Ca/S ratios. Table A.1-3 lists the SO_2 percent removal for different AFBC unit configurations, along with the required Ca/S ratio necessary to achieve that level of emission reduction. The TVA 20 MW(e) with zero recycle represents the traditional, first-generation AFBC unit.

NO_x emissions are also reduced by AFBC (relative to conventional coal-combustion processes). The fluidized state of the bed promotes turbulence which enhances mixing and reduces the maximum bed temperature, typically to 1500^o to 1600^oF. Thermal NO_x formation does not occur in this temperature range. Table A.1-4 summarizes NO_x test data from several different AFBC configurations.

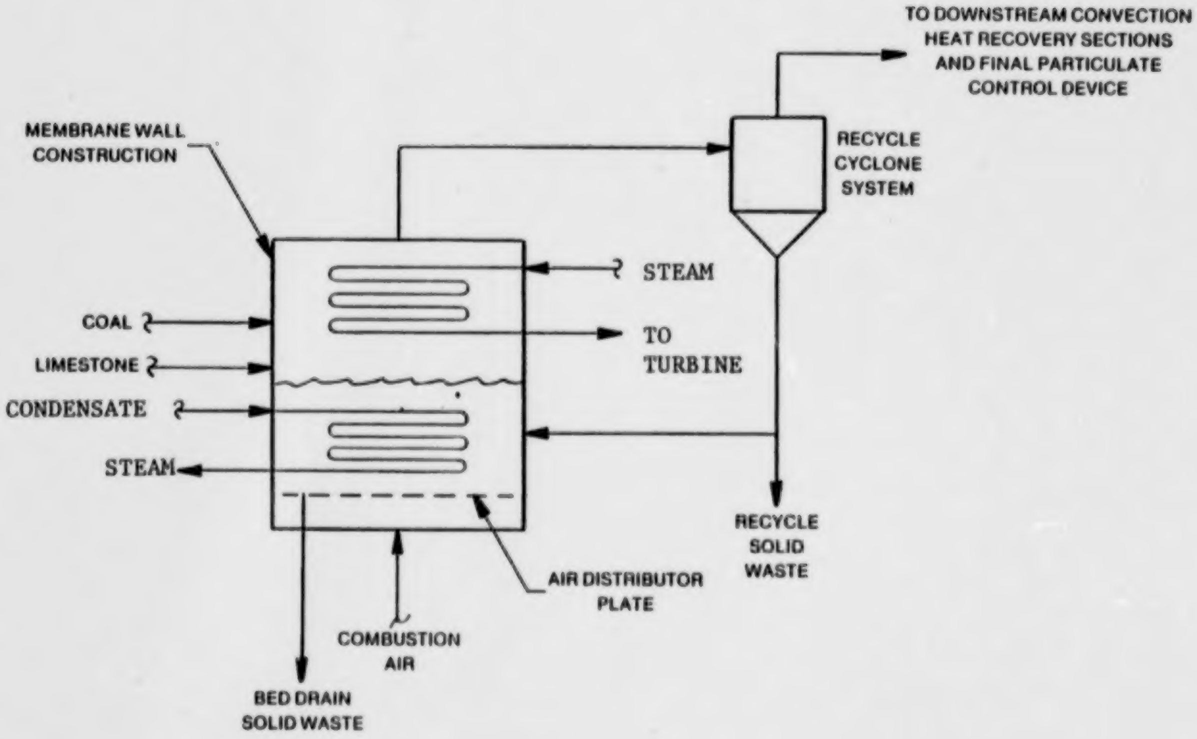
TO DOWNSTREAM CONVECTION
HEAT RECOVERY SECTIONS
AND FINAL PARTICULATE
CONTROL DEVICE
MEMBRANE WALL
CONSTRUCTION
RECYCLE
CYCLONE
SYSTEM
STEAM
COAL
TO
TURBINE
LIMESTONE
CONDENSATE
STEAM
RECYCLE
SOLID
WASTE
AIR DISTRIBUTOR
PLATE
COMBUSTION
AIR
BED DRAIN
SOLID WASTE

Figure A.1-1. Traditional fixed bed combustion flowsheet

TABLE A.1-3. SUMMARY OF SO_2 EMISSIONS CONTROL DATA FROM SEVERAL AFBC CONFIGURATIONS

	SO_2 Control	
AFBC Configuration	Removal	Ca/S
Dense Bed		
TVA 20 MW(e)		
- Recycle Ratio = 0[a]	87%	3.0
- Recycle Ratio - 1.5	98%	3.0
Staged Bed		
Wormser (retrofit)	90%	2.8
Wormser (staged)	95%	2.5
Circulating Bed		
Lurgi (staged)	90%	1.5
Battelle MS-FBC	96%	3.0

[a] Recycle ratio is defined here as the ratio of the mass recycle rate to the mass coal rate.

TABLE A.1-4. SUMMARY OF NO_x EMISSIONS FOR VARIOUS AFBC CONFIGURATIONS

Configuration	NO_x Emissions, lb/10^6 Btu
Dense Bed	
Traditional	0.29 to 0.40
Recycle	0.19 to 0.26
Staged Bed	0.35 (average)
Circulating Bed[a]	0.1

[a] With staged combustion air.

Particulate emissions are controlled by cyclones and fabric filters. Electrostatic precipitators have been used, but the removal efficiencies have been poor. Waste disposal is required for spent limestone and fly ash.

Capacity Limitations: The largest single AFBC in operation produces steam at a rate of 309,000 lb/hr. Steam temperature and pressure are 986°F and 1741 psig, respectively. This corresponds to approximately 40 MW(e). Small units are available which produce 2500 lb saturated steam/hr. Manufacturers offer units with capacities up to 1,100,000 lb steam/hr. Steam temperatures and pressures are available up to 1100°F and 2650 psig, respectively.

Advantages: SO_2 and NO_x emissions are controlled within the combustion chamber, usually eliminating the need for additional pollution control devices such as scrubbers. Even high-sulfur coals are capable of being burned while maintaining emission levels within federal environmental regulations. Alternate fuels or a mixture of fuels can be used with slight modifications to the design.

Disadvantages: Some problems have been encountered with the fuel handling systems. These need further investigation to insure reliability.

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A.2 Technology: External Combustion (Conventional) Boilers/Steam Turbines

Fuels: Coal, natural gas, fuel oil, wood, coke, petroleum coke, process waste liquids, and gases.

Status: Conventional steam boiler and turbine technology has reached a very high state of development. Significant progress is not anticipated for the future. In 1925, a typical steam plant operated at a maximum temperature of 750°F, a pressure of 470 psia, and employed a two-stage steam turbine with three-stage regenerative boiler feed water heating. By 1955, turbines operating at 975°F and 3000 psia using eight-stage regeneration were on-line. During the late 1950's, several supercritical steam power plants were built capable of achieving approximately 41% efficiency. However, it was found that supercritical operation requires materials of construction of such sophistication that any gains in thermodynamic efficiency are offset by added materials costs. Modern steam boilers in large electric utility applications typically produce steam of 950° to 1050° and 2000 to 3000 psia. Medium pressure steam (600 psia) is reheated to 950° to 1050°F. As many as 8 stages of regenerative steam heating may be employed. These features have increased overall electricity generation efficiency to over 35% in new, large electric utilities. However, not all of these features can practically be employed in small plants. For example, large central station units use a reheat steam cycle to increase overall conversion efficiency. In that configuration, the reheater, located within the boiler enclosure, receives steam exhausted from an intermediate pressure stage of the turbine. The steam is reheated to the initial turbine inlet temperature and then returned to the low-pressure section of the turbine. Some plants use double reheat cycles. The reheat cycle is generally impractical for plants less than about 40 MW due to the much increased cost of additional piping and turbine and boiler equipment to accommodate the flow of low-pressure steam. The efficiency of smaller units is also reduced by the inherently lower efficiencies of small boilers and turbines because of a greater percentage of heat losses. Plants of about 20 MW in size, and featuring simple turbine cycles, have overall fuel-to-electricity conversion efficiencies of about 25%.

Description: In a pulverized coal boiler, the coal is pulverized to a powder of which approximately 70 percent will pass through a 200 mesh screen. The coal particles are then entrained in the combustion air and injected into the boiler. Other coal boilers, such as spreader stokers, inject crushed and sized coal onto a moving grate. Small particles burn while suspended in air and larger particles fall to the grate and are combusted in a thin bed. In oil and natural gas fired boilers, oil or gas is mixed with preheated air and injected into the boiler. The fuel then enters the radiant section of the firebox where combustion occurs. In all water-tube boilers, the combustion gases first lose heat by means of radiative heat transfer to water tubes located on the furnace walls. A constriction at the top of the radiant section forces the combustion gases to move at a higher velocity as they pass through the tube banks of the convection section, thus enhancing heat transfer (A.2-5, A.2-3).

The first tube bank in the convection section is typically used to superheat high pressure steam. The second tube bank serves to reheat medium pressure steam. When the combustion gases have become too cool to be used to reheat steam, they are used to preheat boiler feed water in the economizer. Finally, before entering the stack, the combustion gases preheat the incoming ambient combustion air (A.2-3, A.2-5).

In a complete electric generating system, steam from the boilers drives a turbine-generator to produce electricity. Steam condensate from the turbine condenser is recovered and reused as boiler feed water.

Environmental Impact: Direct combustion of fuels in conventional boilers produces air emissions of NO_x, SO_2, and particulates. In addition, the burning of liquid or solid fuels produces a residual bottom ash. Table A.2-1 summarizes emissions from a stoker boiler firing low sulfur Western coal with a lime spray drying FGD system and fabric filters (A.2-3).

TABLE A.2-1. EMISSION FACTORS FOR A STOKER COAL-FIRED BOILER WITH ADVANCED CLEANUP[a]

Pollutant	Emission Rate, lb/10^6 Btu
SO_2	0.08
NO_x	0.45
Particulate	0.01

[a] Low sulfur western coal.

Throwaway flue gas desulfurization (FGD) processes are the most prevalent method of SO_2 control used today. Lime/limestone systems dominate utility SO_2 control while sodium-based processes are more common for industrial boilers. Dry scrubbing systems, using lime or sodium carbonate, are becoming prevalent in both industrial and utility applications. Removal efficiencies of 95% and higher can be achieved with FGD systems applied to boilers firing low sulfur coal.

Methods for controlling NO_x emissions involve 1) modifications to the combustion process to reduce the amount of NO_x generated or 2) removal of the NO_x after it is generated. Firing with low excess air, staged combustion, tangentially fired boilers, and low NO_x burners are combustion modification methods currently used to control NO_x emissions (A.2-6). Combustion modifications can achieve NO_x reductions of 20-50%. Selective catalytic reduction (SCR) can be used to remove NO_x. NO_x reductions at 80% can be achieved with SCR (A.2-3) from the combustion flue gases. While technically feasible, SCR and other add-on NO_x controls are usually very expensive and have received little application in the U. S. to date.

Particulates are controlled with one or more of the following methods: venturi scrubbers, electrostatic precipitators, fabric filters, and mechanical collectors (A.2-6). Removal efficieicies of over 99.9% can be achieved with electrostatic precipitators and fabric filters.

Capacity Limitations: Boilers for electrical production range in size from 20 to 850 MW(e). Over 75 percent of the total electrical power produced in the U. S. in 1979 came from fossil fuel steam plants in this size range (A.2-7).

Advantages: The technology has existed for over 100 years and is well developed and reliable. The units can be designed to fire more than one fuel.

Disadvantages: The emission controls necessary to meet environmental regulations are complex and expensive. Many of the emission control devices produce solid wastes for which disposal is required. Additional solid waste is generated if coal or other solid/liquid fuels are burned.

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A.3 Technology: Gas Turbines

Fuels: Natural gas, diesel fuel, naphtha, methane, crude, low-Btu gases, synthetic fuels.

Status: Industrial heavy-duty gas turbines became commercially available in the 1950's. The use of gas turbines among electrical utiliities throughout the world has increased during the last 15 years. However, utility usage of gas turbines is usually restricted to peak load applications.

Currently, gas turbines operate with turbine inlet temperatures of approximately 2000°F. Inlet temperatures of 3000°F have been projected, and, if achieved, would greatly increase the turbine efficiency. Temperature increases are dependent on the development of more corrosion-resistant alloys and coatings. Thermal efficiencies for gas turbines currently range from 25 to 35 percent, depending on compression ratio and turbine inlet temperature (A.3-4). Using the turbine exhaust to preheat the incoming air can add 3 to 7 percentage points to a turbine's efficiency. Combined cycle systems can further increase the efficiency to greater than 40 percent (A.3-5). These systems use the turbine exhaust to produce steam for expansion in a steam turbine with subsequent generation of additional electricity.

Description: A diagram of the simple-cycle gas turbine is shown in Figure A.3-1. An air compressor is connected to the turbine by means of a shaft. Incoming air is compressed and routed to the combustion chamber. Fuel is added to the combustion chamber and burned. The combustion gases drive the turbine which in turn drives the generator.

The fuel used must not form ash or contain dust or uninhibited vanadium. Ash deposits on the turbine blades interfere with operation. Dust causes erosion of the blades. Vanadium pentoxide serves as a catalyst for oxidation of the metals in the turbine especially with high sulfur levels in the fuel.

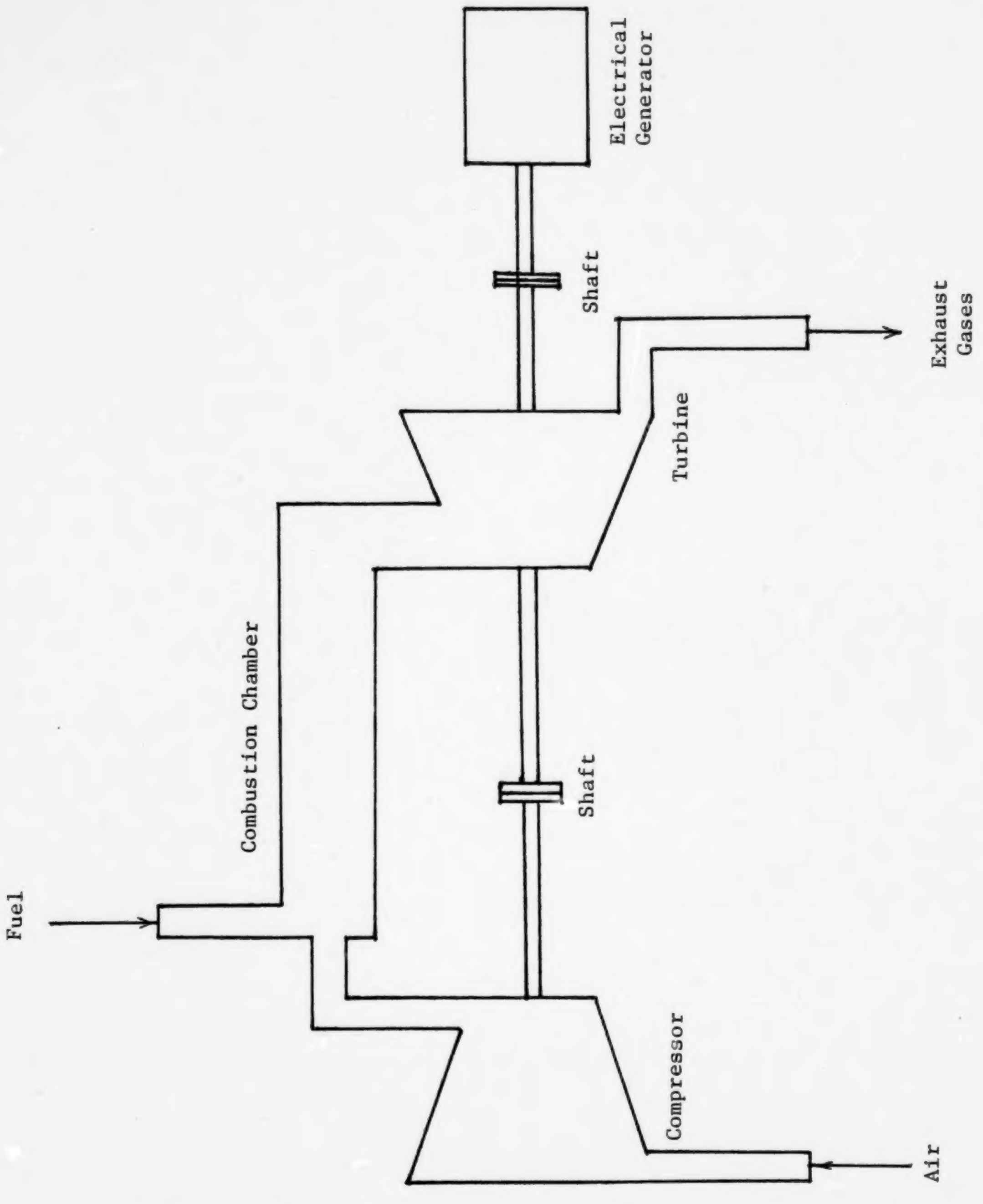
Fuel
Combustion Chamber
Shaft
Compressor
Air
Turbine
Shaft
Electrical Generator
Exhaust Gases

Figure A.3-1. Simple Cycle Gas Turbine.

Both axial and centrifugal compressors are suitable for gas turbine usage. However, due to their greater efficiency, the majority of gas turbine compressors are axial. Because they possess a greater stability, centrifugal compressors are used where a wide operating range is needed.

Two types of turbines are available for gas turbine systems. These consist of the axial-flow type and radial-inflow type. More than 80 percent of all applications utilize the axial-flow turbine.

Two methods are available for increasing the efficiency of gas turbines. Regeneration cycle plants use the turbine exhaust gas to preheat the air fed to the compressor. Combined cycle plants produce steam from the turbine exhaust gases. This steam is used to drive a steam turbine providing electrical generating capacity. If the additional generating capacity is not needed, the steam can be used in a plant process.

Environmental Impact: Since relatively clean fuels are required for gas turbines, stack gas emissions of SO_2 and particulates are usually negligible. However, the high combustion temperatures generate significant NO_x emissions. NO_x emissions can be reduced by injecting steam or water into the compressed air before the combustion chamber. Additionally, low-NO_x burners are being designed and tested to minimize emissions.

Steam or water injected into the compressed air before combustion reduces the temperature in the combustor, thus reducing the amount of NO_x produced. In addition, the oxygen content of the fuel-to-air mixture is reduced, and its heat capacity is increased. This also reduces the combustion zone temperature and the amount of NO_x formed. Steam injection has also been shown to increase cycle efficiency by 1 to 2 percent. Careful control of steam injection is necessary to avoid corrosion problems.

Uncontrolled NO_x emissions from gas turbines can range from 40 to 500 ppmv at 15% O_2. Average NO_x emissions are 90 ppmv for natural gas, 130 ppmv for distillate fuel oil, and 190 ppmv for jet-A type fuel oil. With steam or water injection, NO_x emissions have been reduced by up to 90 percent with water-to-fuel ratios of 1.0.

Emissions of SO_2 are strictly a function of fuel sulfur content with essentially all sulfur in the fuel converted to SO_2. Flue gas desulfurization systems are economically unattractive because of the large gas volumes and low SO_2 concentrations. Distillate fuel sulfur contents range from 0.01 to 0.48 weight percent. Crude oil sulfur contents range from 0.06 to 3.0 percent. Natural gas sulfur content ranges from 0 to 0.1 percent.

Capacity Limitations: The largest gas turbines currently in use have net electrical outputs of approximately 80 MW. Small gas turbines which produce less than 4 MW are also available.

Advantages: The gas turbine is a proven, very reliable technology. The lead time for construction and startup is short, only about 2 years as compared to 6 to 8 years for most large fossil fuel utility units. The gas turbine power plant can be assembled in the manufacturer's facility and tested before shipment. Gas turbines are capable of being started and brought on-line within 5 to 20 minutes.

Disadvantages: Gas turbine fuels must have low sulfur content to prevent corrosion problems. The fuel must be free of dust and not produce ash while burning. The fuel's vanadium content must also be low. As a result of these requirements, gas turbine fuels are expensive. If a regenerator, combined cycle, or cogeneration system is not employed, a low thermal efficiency results. The low thermal efficiency and expensive fuels combine to produce a high operating cost.

Emission of NO_x must be reduced to comply with environmental regulations. Methods such as water or steam injection reduce NO_x, but also speed corrosion. Noise is an additional problem encountered with gas turbines.

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A.4 **Technology**: Internal Combustion Engines (Diesel Engines)

Fuels: Diesel oil, gas, No. 2 fuel oil, No. 6 fuel oil

Status: Electric power generation by the internal combustion engine and generator was an established technology by 1892 (A.4-2). The technology is currently well-developed and very reliable. The present generation of U.S.-made engines have existed since the early 1970's or before. Manufacturers have made only limited efforts to upgrade capabilities or develop new designs (A.4-1). Table A.4-1 lists manufacturers offering engines suitable for electrical power generation (A.4-3).

TABLE A.4-1. MANUFACTURERS OF ENGINES SUITABLE FOR ELECTRICAL POWER GENERATION

Alco Power, Inc.
Caterpillar Tractor Co.
Cummins Engine Co.
Delaval Engine & Compressor Div.
Fairbanks Morse Engine Div./Colt Industries
General Motors Corp.
Ingersoll-Rand
KHD Deutz Corp.
Sulzer Brothers, Inc.
Waukesha Engine Div./Dresser Industries
White Motor Co.
Worthington, Corp.

Description: Internal combustion engines used for electric power generation operate in one of two cycles, Diesel or Otto, which can be further divided into 2 or 4-stroke engines. The majority of engines used to generate baseload electricity are based on the Diesel cycle.

In the 4-stroke Diesel engine, air is drawn into a cylinder by a piston moving downward. The air flow is stopped, and the cylinder is sealed as the piston reaches the bottom of its stroke. The upward travel of the piston compresses the air and raises its temperature. As the piston reaches the top of its stroke, fuel injection begins. The fuel-air mixture undergoes auto-ignition and drives the piston downward. Fuel injection continues so that burning occurs at a constant pressure. The power produced by the expanding combustion gases is transferred from the piston's linear motion to a circular motion by means of a rotating shaft connected perpendicular to the piston's travel. Fuel injection stops as the piston starts back upward, and the combustion gases are driven out. The cycle then starts over with the intake of air on the downward stroke (A.4-5).

The 4-stroke Otto cycle is similar to the 4-stroke Diesel cycle except that a fuel-air mixture is drawn in on the intake stroke, compressed by the upward stroke, and ignited by a spark as the piston reaches the top of the cylinder. In this case combustion does not occur at constant pressure (A.4-5).

Engines can complete the power cycle in two strokes by removing combustion gases at the end of the power-producing stroke. This is accomplished by blowing air (or an air-fuel mixture) into the cylinder at the end of the power stroke, thus eliminating the exhaust stroke (A.4-5).

A complete internal combustion engine can have as many as 20 cylinders with the pistons all connected to a common rotating shaft. Electricity is produced by connecting the shaft to a generator. The production of 60 hertz alternating current electricity requires the engine's shaft to rotate at some multiple of 60 revolutions per minute (RPM) if the shaft is connected directly to the generator. Most engines used for electrical power production operate at 900 RPM or less, although a few operate at 1200 RPM.

The Diesel cycle has a lower efficiency than the Otto cycle for a given compression ratio. However, pre-ignition difficulties limit the compression ratio in an Otto engine. Higher ratios can be used in the Diesel engine resulting in higher efficiencies. Fuel to electricity efficiencies are approximately 37% (A.4-8). Both 2 and 4-cycle Diesel engines are in wide-spread usage.

Environmental Impact: Emissions of NO_x, CO, and non-methane hydrocarbons for a 6.4 MW dual-fuel engine-generator set were 6 g/bhp-hr, 2.2 g/bhp-hr, and 1 g/bhp-hr, respectively. The same unit operating on diesel only had NO_x emissions which increased to 9 g/bhp-hr. Emissions of SO_2 are fuel-dependent since essentially all the sulfur in the fuel is transformed into SO_2. For a fuel containing less than 0.05% sulfur, the above-mentioned unit had SO_2 emissions of 0.047 g/bhp-hr. All emission rates are given at 100% load (A.4-6).

Capacity Limitations: The largest units in use today produce approximately 24 MW net electrical power from a single engine. Units producing around 7 MW and lower are much more common. Facilities requiring larger capacities usually consist of two or more engine-generator sets. Capacities range all the way down to a few kilowatts (A.4-3, A.4-2).

Advantages: Internal combustion engine technology is well-developed and very reliable. The oil or gas engine still remains the most efficient power source available for in-plant generation. The engine's ability to be started up in a few minutes has generated wide-spread use of internal combustion engines for standby and emergency power use. Most plants producing more than 8 MW use more than one engine-generator set allowing units to be added or dropped to meet load changes. The costs per kilowatt and lead time (1 year) are lower for engine-generator sets than for coal-fired baseload plants.

Disadvantages: The dependency of the internal combustion engine on oil and gas is a major drawback. Clean fuels, which are expensive, are required; otherwise a maintenance penalty is incurred in the operating cost. The limited sizes available can be a disadvantage in terms of space for systems larger than 8 MW. With the current emphasis on heat recovery and cogeneration the internal combustion engine is not favored. Engine exhaust can generally produce only very low-pressure steam or hot water, unless an organic Rankine-cycle heat-recovery system is installed. However, this increases the capital cost and complexity of the facility.

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A.5 Technology: Fuel Cells

Fuels: Hydrogen via processing of natural gas (methane), ethane, propane, butane, naphtha, jet fuel, gasoline, heating oil, methanol, hydrogen, coal.

Status: There are several types of fuel cells, distinguished by the electrolyte used. The three electrolytes currently undergoing research and development are phosphoric acid, molten carbonate, and solid-oxide. Of these three, phosphoric acid fuel cells hold the best promise for near-term commercialization. Molten carbonate and solid-oxide fuel cells are at least 8-10 years away from commercial use, with molten carbonate ahead of solid oxide.

United Technology Corporation, Westinghouse Electric Corporation, and Engelhard Industries have been doing the majority of the fuel cell research and are the most likely future commercial manufacturers. United Technology is currently operating a 4.8 MW(e) prototype unit in New York.

Description: A fuel cell is an electrochemical device which directly converts a fuel into direct current electricity without an intermediate combustion step. A fuel cell consists of two electrodes submersed in an electrolyte. The electrolyte will transmit ions, but not electrons. Hydrogen from a fuel processor is supplied to the negative electrode, and air or pure oxygen is supplied to the positive electrode. The hydrogen dissociates into hydrogen ions and electrons. The hydrogen ions migrate through the electrolyte while the electrons move through an external circuit to the positive electrode, setting up a direct current. The hydrogen ions, oxygen, and electrons combine to form water at the positive electrode. Heat is also generated which must be removed to prevent damage to the fuel cell.

A single fuel cell produces between 0.5 and 1.0 volt dc at a current that is proportional to the cell area. Individual fuel cells are arranged in stacks to form a unit with a voltage output equal to the product of the voltage per cell and the number of cells. Heat produced during the electrochemical process is removed through large cooling plates incorporated into the stack.

Phosphoric acid fuel cells must be operated between 300° and 400°F. Below 300°F phosphoric acid has a low conductivity, and above 400°F the electrode material becomes unstable. Large quantities of low pressure steam (375°F and 180 psia conditions are typical) are generated. If this steam is not used, a significant energy penalty is incurred.

Effective operation of the phosphoric acid fuel cell requires continuous saturation of the negative electrode with hydrogen. This maximizes the cell amperage. As a result of the continuous hydrogen saturation, a certain amount of unreacted hydrogen gas is exhausted from the surface of the negative electrode. Approximately 10 to 15 percent of the total hydrogen fed to the cell passes through unreacted. This hydrogen can usually be utilized in the fuel processor.

A fuel cell power plant requires three sections: a fuel processor, the fuel cell power section, and a power conditioner. The fuel processor converts a hydrocarbon fuel into a hydrogen-rich gas for use by the fuel cells. Coal gasification or steam reforming of petroleum feedstocks are possibilities for fuel processors. The power conditioner converts the direct current to alternating current. Power conditioning technology is highly developed with losses less than 4 percent of input power. The power conditioner also serves to smooth out voltage fluctuations produced by the fuel cells.

Environmental Impact: The fuel cell power stack produces no emissions other than the pass-through hydrogen gas from the negative electrode. The content of this gas is a function of the fuel processor. If the fuel cell power stack is integrated with the fuel processor, the emissions are essentially the same as those for the fuel processor alone.

Capacity Limitations: The modular construction of the fuel cell power stacks allows capacities of virtually any size to be constructed. Therefore, the size of a fuel cell power plant is only limited by the fuel processor size restrictions.

Advantages: Since the fuel cell does not depend on an intermediate fluid (e.g., steam in a steam turbine, gas in a gas turbine, or an internal combustion engine), the thermodynamic efficiency is not limited as are turbines and engines. This allows a potentially high electrical generation efficiency. The size is flexible due to the modular construction. Operation is essentially automatic. Emissions for the fuel cell alone are very low and depend on the contents of the hydrogen-rich fuel. The fuel cell has a virtually flat response curve and excellent load following capability.

Overall efficiency of a typical integrated gasifier/fuel cell system is estimated at 33% (A.5-1). Fuel cells alone have a 54-61% efficiency range.

Disadvantages: The phosphoric acid fuel cell, as well as the molten carbonate fuel cell, is very sensitive to sulfur species present in the fuel gas. The negative electrode in the phosphoric acid fuel cell is also sensitive to carbon monoxide present in the fuel gas. Therefore, the phosphoric acid fuel cell required virtually pure hydrogen gas as fuel. All potential fuels have to be converted into hydrogen.

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A.6 Technology: Wind Energy

Fuel: Wind

Status: The earliest recorded use of wind energy occurred during the seventh century in the Middle East. These early models were all of a type having a vertical axis. The horizontal axis, propeller type of sail (typified by the Dutch windmill) appeared in the twelfth century and reached a peak in the seventeenth and eighteenth centuries. The steam engine, steam turbine, and internal combustion engine led to the decline of windmills except for rural use for grinding grain and pumping water. Rural electrical generation by wind machines in the U. S. spread rapidly during the 1930's and 1940's with the introduction of the Jacob's 3 kW machine. Hundreds of thousands of wind-electric systems were successfully used on farms and homesteads. However, their use declined rapidly as the Rural Electrification Authority spread grid power throughout the country areas. The first large-scale wind-powered system was erected in 1941 in Vermont. The Smith-Putnam turbine produced 1.25 MW and, at one time, was coupled to a local utility for a continuous period of several weeks. The two-bladed, 175 foot diameter prop withstood winds as high as 115 mph before catastrophically falling in 1945 in a 25 mph wind. Over 30 years passed before interest in large-scale wind systems was renewed by the construction of a 2 MW unit at Tvind in Denmark during 1978. Research is currently being conducted by NASA on systems ranging in size from 0.1 to 4.0 MW (A.6-1). Wind energy technology is considered commercial with most research directed at optimizing performance and reducing costs.

Description: The most important factor to be considered in the generation of electricity by wind turbines is the constant availability of high-velocity winds. Since the power output is proportional to the cube of the wind velocity, most small-scale units (<100 kW) require "cut-in" wind velocities of about 8 mph. The cut-in wind velocity is the velocity required before power generation occurs. Large units (>500 kW) generally have cut-in wind velocities of 10 to 15 mph. Rated output for large-scale units does not occur until the wind velocity reaches 18 to 40 mph. Therefore, the wind turbine should be sited where winds blow almost continuously with high velocity. However, turbulent winds should be avoided. Topographical features such as valleys and smooth hills can augment wind speed and increase the amount of power available for wind turbines.

Energy is obtained from the wind by slowing the air velocity. However, the wind turbine can not extract all of the energy from the wind since this would require the air behind the wind turbine to come to a complete standstill. It can be shown that a windmill derives the maximum amount of power when the wind is slowed to one-third of its initial velocity. This results in an ideal power output of 59.3 percent of the wind's power. However, the most efficient wind turbine designs only achieve about 35 percent conversion of wind energy to electrical energy.

The basic wind turbine system consists of a rotor, gearing, generator, and tower as illustrated in Figure A.6-1.

Wind machine rotors can be classified according to their orientation of the axis of rotation to the direction of the wind. Rotors with their axis parallel to the wind direction are called horizontal rotors. These rotors require a means of keeping the rotor facing into the wind. Vertical axis rotors have their axis perpendicular to the wind stream and can easily accept wind from any direction. They are usually employed when wind direction constantly shifts.

Rotors can be further classified as "drag" or "lift" type. Drag type rotors have lower efficiencies, but develop higher torque at low speed. These are generally used for pumping and grinding applications. An example is the multiblade turbine commonly seen pumping water on farms. Lift type rotors produce power from drag forces plus force from lift due to the airfoil shape of the blade. These rotors are characterized by higher speeds and efficiencies, but lower torque. Most lift type rotors have only 2 or 3 blades and resemble airplane propellers. The production of electricity over 0.5 MW

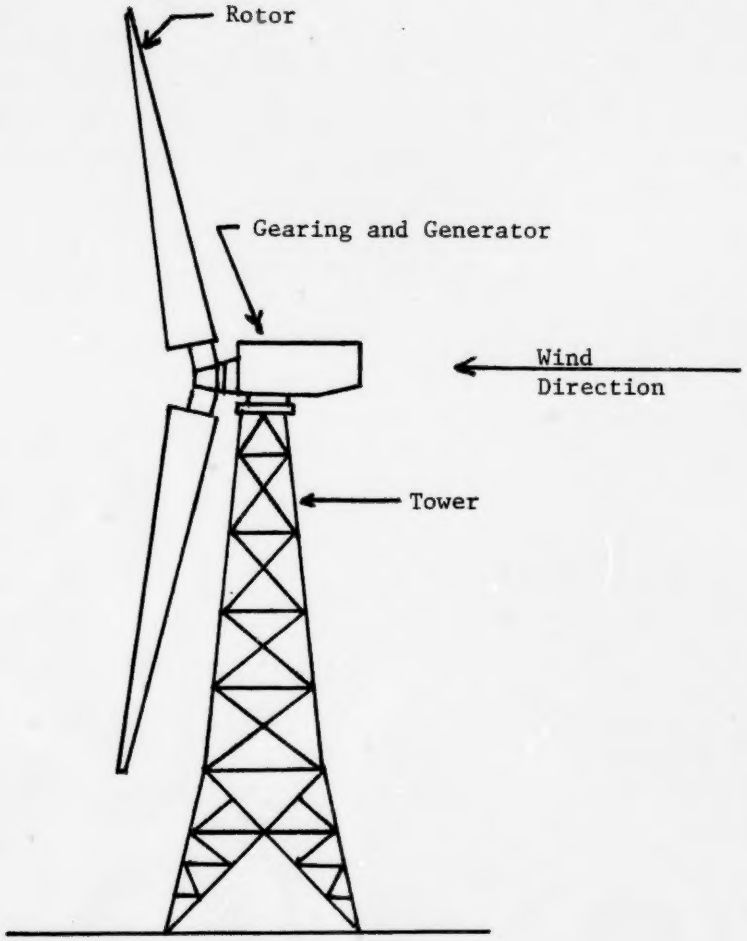

Rotor
Gearing and Generator
Wind
Direction
Tower

Figure A.6-1. Basic wind turbine system (A.6-1)

is almost exclusively performed by propeller-type, horizontal axis wind turbines.

Rotor blades may be constructed of steel, aluminum, fiber-reinforced plastic composites, wood, or a combination of these. Large-scale wind turbine rotors have been constructed from all of these materials. Rotor diameters can range from 80 ft for 0.2 MW to 300 ft and larger for 3.0 MW. Since the power output is proportional to the square of the rotor diameter, a small change in rotor size can cause a large change in the power output.

The gearing and generator of a wind turbine are generally contained in a single unit. The drive train consists of a low-speed rotor shaft (generally around 40 rpm for large-scale wind turbines), gearbox, high-speed shaft driving the generator, possibly a slipping clutch for torque overloads, and a disk brake. All large wind turbines to date have standard frequency (50 to 60 Hertz) induction or synchronous generators. Synchronous generators with 1800 rpm operating speeds are more common in the United States. Synchronous generators allow direct grid tie in. Induction generators are generally used in Europe.

Tower design is changing from a stiff, open-truss mode to a soft, cylindrical construction. (Stiff and soft refer to the natural bending frequency of the tower.) A soft tower is generally less expensive than a stiff one, and its blockage effect on downwind rotors can be more readily estimated. Soft towers are usually constructed of concrete with a steel shell. Since wind speed normally increases with increased height, it is desirable to locate the rotor as high as possible. Large-scale tower heights range from 80 to 330 feet (A.6-1).

Environmental Impact: Wind turbines produce no thermal or chemical pollution. However, interference with electromagnetic communications is a possibility. Television video reception can be disturbed at distances up to a few kilometers. Interference with FM radio frequencies appears not to be serious, but there is some possibility for microwave and aircraft navigational system interference (A.6-1). All of the interference phenomena have been reported from large-scale wind tower applications. No interference has been reported for small wind turbines.

Noise from large-scale wind turbines is insignificant at the usual minimal approach distance, but the NASA MOD-1 turbine at Boone, NC was found to generate a very low frequency pulsation which could be felt in homes some distance away (A.6-2).

Capacity Limitations: Wind turbines are commercially available in sizes from less than 1 kW to200 kW. Several prototypes are in operation in sizes ranging from 0.5 kW to 4.0 MW Manufacturers of the large-scale units include Boeing, General Electric, Hamilton Standard, and Westinghouse (A6-1).

Advantages: Wind turbines produce no thermal or chemical pollution and require little maintenance. Wind energy is derived from solar energy and is regarded as indefinitely renewable and inexhaustible.

Disadvantages: Wind turbines are a possible source of interference to electromagnetic communications. Systems producing in the MW range are still in the prototype stage. In addition, thes systems require continuous high velocity winds to produce electricity at their rated output.

References:

A.6-1 Meyers,R.A., editor. Handbook of Energy Technology and Economics. John Wiley & Sons. New York, pp.826-876,1983.

A.6-2 Carter Wind Systems, Inc. Brochure on Model 250 (250 kW). Form C-16-84. 1984.

A.6-3 Wind Energy Report (Newsletter) , 6(14):105-112, July 29,1983.

A.6-4 Letter from Tom Zombrano (Aeroevironment, Inc.) to Tom Green (Radian Corp.) re. Wind Resource Evalutation at VAFB, Dec. 14, 1983.

A.6-5 Personal communication between A. F. Jones (Radian Corporation) and Carter Wind Systems, 8 October 1983.

A.6-6 Personal communication between P. J. Murin (Radian Corporation) and Ward Slager (Carter Wind Systems) 12 April 1984.

A.7 Technology: Solar Central Receiver (Power Tower)

Fuel: Solar Energy

Status: Several experimental central receiver systems have been constructed in the U. S. and abroad,including a 5 MWt test facility in Albuquerque, New Mexico (A.7-1).

A 10 MWe solar power tower pilot plant in California, known as the Solar One, began operation in April 1982. The plant is a cooperative effort between the Department of Energy, Southern California Edison Company, Los Angeles Department of Water and Power, and the California Energy Commission. The current test program is devoted to the design verification of the individual systems and components and demonstration of the various modes of operation. Starting in 1984, three years of operation will begin to demonstrate plant reliability and maximize kWh output (A.7-1). Southern California Edison (SCE) has a 100 MWe power tower plant planned (A.7-1).

Description: The following is a description of the Solar I pilot plant illustrated in Figure A.7-1 (A.7-2).

Sunlight strikes a field of 1,818 sun tracking mirrors (heliostats) and is reflected to a central receiving tower. The heliostats form a fairly circular 72 acre field with the receiver tower located south of the center. Each heliostat has 430 square feet of reflective area and is capable of computer-controlled rotation of two axes, azimuth and elevation. Average reflectance of a clean heliostat mirror exceeds 91 percent.

The central receiving tower stands 298 feet high with the circular solar receiver occupying the top 45 feet. The receiver consists of 24 panels covered with a high absorptivity coating. Six pre-heater panels are located on the south side of the receiver, with the remaining 18 boiler panels located on the west, north, and east sides. Extensively demineralized feedwater (e.g., 10 ppb iron, 2 ppb sodium, 2 ppb chloride) is required for the receiver. Steam exits at 960°F and 1510 to 1570 psig.

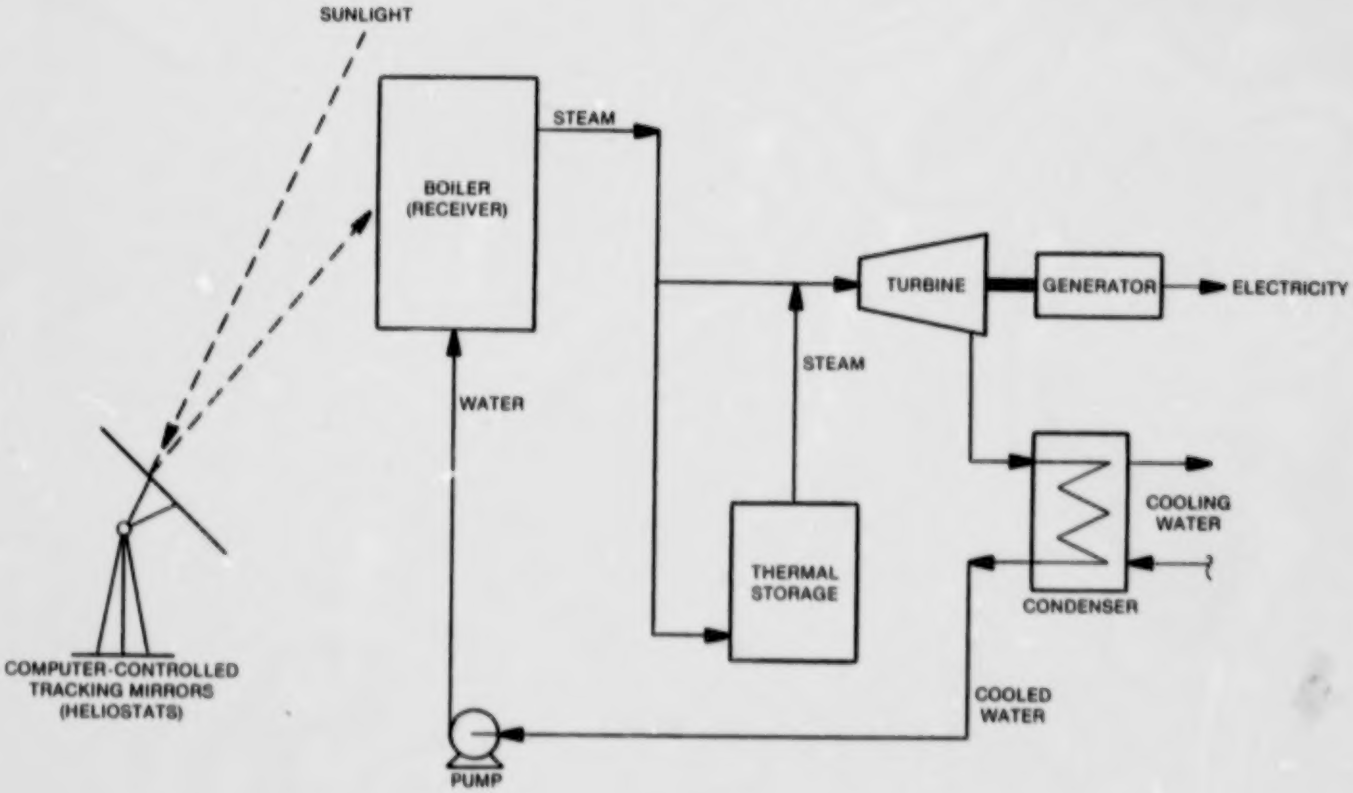

SUNLIGHT
BOILER (RECEIVER)
STEAM
TURBINE
GENERATOR
ELECTRICITY
STEAM
WATER
THERMAL STORAGE
COOLING WATER
CONDENSER
COOLED WATER
COMPUTER-CONTROLLED TRACKING MIRRORS (HELIOSTATS)
PUMP

Figure A.7-1 Simplified Schematic of a Solar Thermal Power Plant (A.7-2)

The steam is then directed to a conventional turbine which operates at 3600 rpm and is directly coupled to a 13.8 kV generator. The unit is rated and guaranteed at 12.8 MWe gross electrical output with steam inlet conditions of 960°F, 1465 psia, and 112,000 lb/hr. Exhaust steam is routed through a condenser and pumped back to the solar receiver.

During periods when excess steam is available, it is directed to a thermal storage system for use during periods when no sun is available. The thermal storage unit consists of an insulated cylindrical tank filled with a sand/rock mixture through which caloria oil passes. The caloria passes through a heat exchanger and is heated by the excess steam. The oil is then introduced to the top of the tank, transferring heat to the rock and sand mixture as it flows downward. Inlet oil temperature is approximately 580°F; outlet temperature is approximately 425°F. This continues until excess steam is no longer available or the storage tank is fully charged. The discharge cycle is capable of producing 525°F, 380 psia steam for use in the steam turbine.

The maximum estimated daily energy production ranges from 112 MWe-hr (June 21) to 48 MWe-hr (December 21). The annual estimated energy generation is 26,000 MWe-hr (365 day operation). The gross plant efficiency ranges from 15.4 percent in winter to 17.4 percent in summer (A.7-2). SCE's planned 100 MWe power tower plant is projected to have a sun-to-electricity efficiency of about 20 percent by using a liquid sodium working fluid (A.7-3).

Environmental Impact: Solar power towers produce no chemical pollution. The oil used in the thermal storage system decomposes slowly producing non-condensible waste gas such as methane, ethane, and hydrogen which must be flared.

Capacity Limitations: More operating experience is required before the limitations on capacity can be determined. However, systems of up to 500 MWt have been designed for a single tower and receiver.

Advantages: Solar power towers utilize energy from sunlight and produce no chemical pollutants.

Disadvantages: Solar power towers use beam (direct) radiation and therefore, must be located in areas which have a large percentage of cloudless days. The equipment must be able to endure the thermal stress resulting from the large temperature range encountered in the cyclic operation.

References:

A.7-1 Meyers, R. A., editor. Handbook of Energy Technology and Economics. John Wiley & Sons. New York, NY. pp. 618-664. 1983.

A.7-2 Solar One Visitor Center. Solar 10-MWe Pilot Plant. May 1983.

A.7-3 Information obtained by Tom Green (Radian Corporation) from Spencer Carlisle (Southern California Edison).

A.8 Technology: Solar Photovoltaics

Fuel: Solar Energy

Status: The photovoltaic effect in electrolytic cells was discovered in 1839. Although cells were constructed of several materials before 1954, their efficiencies were less than 1 percent. The purified silicon monocrystal, developed in 1954, allowed construction of a photovoltaic cell with a 6 percent efficiency. Silicon cells were available commercially in 1955, but the cost was extremely high. The first cells were used for terrestrial applications. In 1958 with the first satellite launching, silicon cells became the almost exclusive power source for satellites due to their low weight. Terrestrial use of solar cells did not become significant until 1975 when cells of 18 to 19 percent efficiency became available. The cost of silicon cells still limit their use to mostly remote applications (A.8-1, A.8-2). However, ARCO Solar, Inc., a subsidiary of Atlantic Richfield Company, and Southern California Edison are currently operating a 1.0 MW photovoltaic power plant in Hesperia, California. ARCO also has a 16 MW photovoltaic plant planned in conjunction with Pacific Gas and Electric Company. The plant will be built in two phases. Phase I, with a 6 MW capacity, is planned for a March 1984 startup. The date of the second phase, a 10 MW addition, has not been set (A.8-3).

Description: Photovoltaic power plants are composed of strings of silicon cells wired in series and mounted on panels which track the sun. The silicon cells, which directly convert sunlight into electricity, are sealed between sheets of glass or polymer for protection. The balance of the system is made up of power regulation and conditioning equipment.

Two major categories of photovoltaic energy systems are currently in use: flat-plate collector systems and concentrating collector systems. In flat-plate systems, solar cells typically cover almost the entire sun-exposed area of the collectors. They can either be positioned in a fixed southerly direction with tilt angles approximately equal to the local latitude or be mounted on plates which track the sun's path. Tracking is reported to provide

40 percent more kWh than fixed flat plate systems (A.8-3). These systems operate in both direct and diffuse light.

In concentrating systems the area exposed to the sun is covered with lenses, mirrored parabolic reflectors, and/or heliostat arrays which focus sunlight onto a small number of typically high performance solar cells. Concentrating systems use only the direct component of the sunlight and therefore must track the sun's path in a least one axis to achieve efficient operation. Cooling must be used at high levels of solar concentration to avoid excessive temperatures and loss of cell efficiency (A.8-1).

The ARCO 1.0 MW photovoltaic plant uses the flat plate collector method with tracking on two axes. Overall efficiency (sunlight to AC) is approximately 9.0 percent. Nine acres of land are required compared to about 20 acres for a non-tracking 1.0 MW plant. The extra area is needed to prevent plates from being blocked during operation early and late in the day. The 16 MW photovoltaic plant will use tracking, reflector-enhanced flat plate collectors. Reflector enhancing provides about 50% peak power improvement. In addition, the individual silicon cells will be square instead of circular or elliptical. Overall efficiency will be approximately 13.5 percent. (A.8-4).

Environmental Impact: Solar photovoltaic plants produce no chemical pollution.

Capacity Limitations: The modular nature of solar photovoltaic systems allows plants of virtually any size to be built (A.8-1, A.8-2). Land availability is the major design constraint.

Advantages: Photovoltaic cells convert sunlight directly into electricity with no intermediate thermal step or pollution. The cells are very reliable and involve no moving parts unless sun-tracking mechanisms are employed. The cells can operate in both direct and diffuse light, although tracking systems can utilize only direct sunlight.

Disadvantages: Large solar photovoltaic systems require large amounts of land (up to 20 acres per megawatt) (A.8-3). At present, the initial capital cost is very high. Although the capital cost will undoubtedly decrease, the timing for future economically viable systems is unknown.

References:

A.8-1 Meyers, R. A., editor. Handbook of Energy Technology and Economics. John Wiley & Sons. New York, NY. pp. 663-711. 1983.

A.8-2 Palz, W. Solar Electricity. Butterworth Publishers, Inc. Boston. pp. 179-217. 1978.

A.8-3 Personal communication with the following silicon photovoltaic cell vendors: Michael Pecora (Solar Power Corporation), Sue Jones (Photowatt International, Inc.).

A.8-4 Information obtained by Tom Green (Radian Corporation) from Spencer Carlisle (Southern California Edison).

A.9 Technology: Pumped Hydro

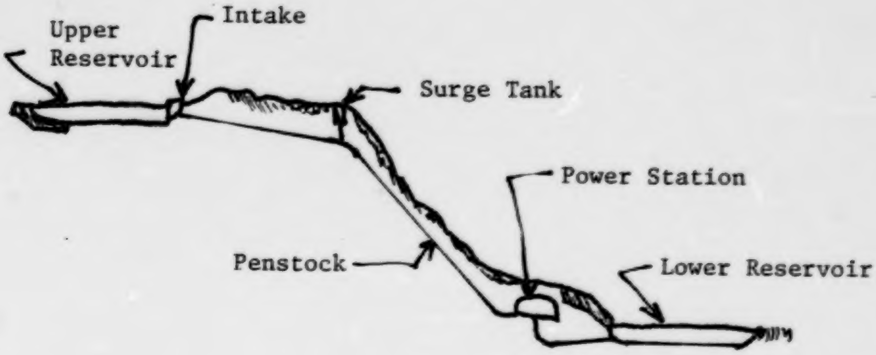
Fuels: Water Head, Electricity

Status: Pumped hydro generating capacity, used for peak load applications, can be classified as conventional pure pumped storage, conventional pumped storage combined with runoff, and underground pumped storage. Conventional pure pumped storage and conventional pumped storage with runoff utilize two surface reservoirs located at different elevations. Both conventional pumped storage technologies transfer water between the two reservoirs. The difference between the technologies is that pumped storage with runoff also generates electricity from collected runoff water. Underground pumped storage employs an upper surface reservoir and a lower underground reservoir.

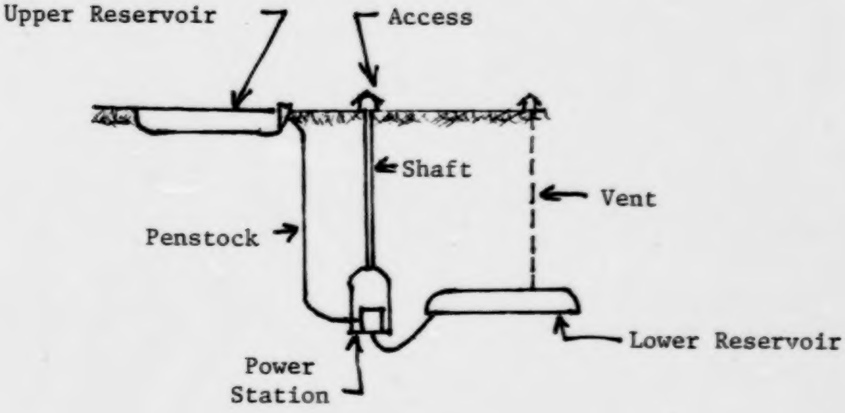
Conventional hydro pumped storage, both pure and combined with runoff, has been used extensively, especially abroad. Although the first pumped hydroelectric plant went on line in 1929 (A.9-1), development lagged in the United States until the 1950's when reversible pump/generator units were developed by the Allis-Chalmers Company (A.9-2). As of mid-1981, approximately 13,000 MW of pumped storage capacity was operating in the United States (A.9-1). This capacity exists in approximately 30 plants, most of which operate at heads above 300 feet and employ individual units larger than 100 kW (A.9-2, A.9-3). New plants under construction or planned show a trend toward higher heads, up to 1000 feet or more, and larger individual units, generally about 250 MW.

Underground pumped hydro is currently undergoing feasibility studies, but no installations are planned for the near future.

Description: Both conventional pure pumped hydro and pumped hydro combined with runoff are described by the same system. Figure A.9-1 illustrates the conventional pumped hydro system. The system consists of two surface reservoirs at different elevations connected by a pipe or tunnel (denoted as a penstock). Elevation difference, or head, usually ranges from


Upper Reservoir
Intake
Surge Tank
Power Station
Penstock
Lower Reservoir

Conventional Pumped Hydro


Upper Reservoir
Access
Shaft
Vent
Penstock
Lower Reservoir
Power Station

Underground Pumped Hydro

Figure A.9-1. Pumped hydro schemes (A.9-4)

100 to 1500 feet. Off-peak energy is supplied to a combined pump/generator to pump water from the lower reservoir to the upper reservoir. During peak electrical demand, electricity is generated by allowing the water in the upper reservoir to flow through the penstock and pump/generator to the lower reservoir. The efficiency of the conventional pumped hydro system is about 70 to 75 percent, expressed as input electrical energy to output electrical energy (A.9-1).

Proposed underground pumped hydro systems should have approximately the same efficiency. However, the underground pumped hydro system requires only one surface reservoir as illustrated. The lower reservoir would consist of an underground excavated cavern located at depths as great as 5000 feet. Placing the underground cavern as deep as possible required smaller reservoirs since higher heads are involved. Since current reversible pump/generator units are limited to pumping heads of 2000 feet, an intermediate reservoir and more than one pump/generator unit would have to be used for heads of over 2000 feet.

Environmental Impact: Pumped hydro generating plants produce no air or water emissions and very little noise. The reservoirs for a conventional system may remove land that is currently in agricultural use.

Capacity Limitations: Existing conventional pumped hydro plants range in size from about 10 MW to 2000 MW (A.9-3). Plants are large as 3500 MW have been proposed (A.9-5).

Advantages: Conventional pumped hydro plants have relatively low investment costs, long life (>50 years), and no air or thermal pollution. Startup is rapid and in emergencies can be initiated with no outside electrical power (black start) (A.9-3). Underground pumped hydro plants have the advantage over conventional plants of requiring only one surface reservoir.

Disadvantages: The surface reservoir(s) required could cover land used for agricultural purposes. The reservoirs also require long construction times. Any excavated material must be moved or formed into an acceptable surface formation.

References:

A.9-1 Berman, I. M. "Development in Energy Storage Technology." *Power Engineering*. pp. 46-50. July 1983.

A.9-2 Loane, E. S. *Introduction to Session on "Surface and Underground Pumped Storage and Compressed Air Storage"*. Proceedings of Energy Storage: User Needs and Technology Applications. GPU Service Corporation. pp. 245-246. February 1976.

A.9-3 United States Department of Energy. *Hydroelectric Plant Construction Cost and Annual Production Expenses - 1979*. U. S. DOE Report No. DOE/EIA-1071(79). March 1982.

A.9-4 Mitchell, W. S. *Underground Pumped Hydro Storage*. Proceedings of Energy Storage: User Needs and Technology Applications. Harza Engineering Company. pp. 247-263. February 1976.

A.9-5 United States Department of Energy. *Hydroelectric Plant Construction Cost and Annual Production Expenses - 1976*. U. S. DOE Report No. DOE/EIA-0006/20. May 1978.

A.10 Technology: Steam Reforming

Fuels: Natural gas, refinery off-gases, LPG, naphtha

Status: The production of hydrogen by steam reforming hydrocarbons was first invented and applied by BASF in the years 1926 to 1928. The technology did not advance significantly until after World War II. The last 30 years have seen rapid improvements in the process as a result of the interest in steam reforming for large-scale production of low-cost ammonia and methanol. More recently, the extensive use of hydrogen in petroleum refineries for hydro-cracking petroleum fractions has created the need for large capacity hydrogen plants (A.10-1). Steam reforming is the most widely used process for the production of hydrogen (A.10-2).

Description: The typical steam reforming process for hydrogen production is illustrated in Figure A.10-1 (A.10-1). A light natural gas-type product or heavier hydrocarbon mixture such as naphtha is desulfurized to prevent catalyst deactivation. Desulfurization methods include ambient temperature adsorption on activated carbon, high temperature reaction with zinc oxide, and catalytic hydrogeneration followed by reaction with zinc oxide.

Desulfurized feedstock is mixed with superheated steam and passed through catalyst-filled tubes in the steam reforming furnace. Temperatures inside the tubes are approximately 1400° - 1600°F. A nickel catalyst is used for light hydrocarbon feedstock; heavier hydrocarbon feedstocks require a special catalyst.

Hydrogen, carbon monoxide, carbon dioxide and excess steam constitute the reformed gas. This gas is cooled and passed through a shift converter where carbon monoxide is reacted with steam to produce hydrogen and carbon dioxide. The shift conversion occurs in two separate catalyst beds, a high temperature bed and a low temperature bed. The gas is cooled between the beds. The catalyst used is iron.

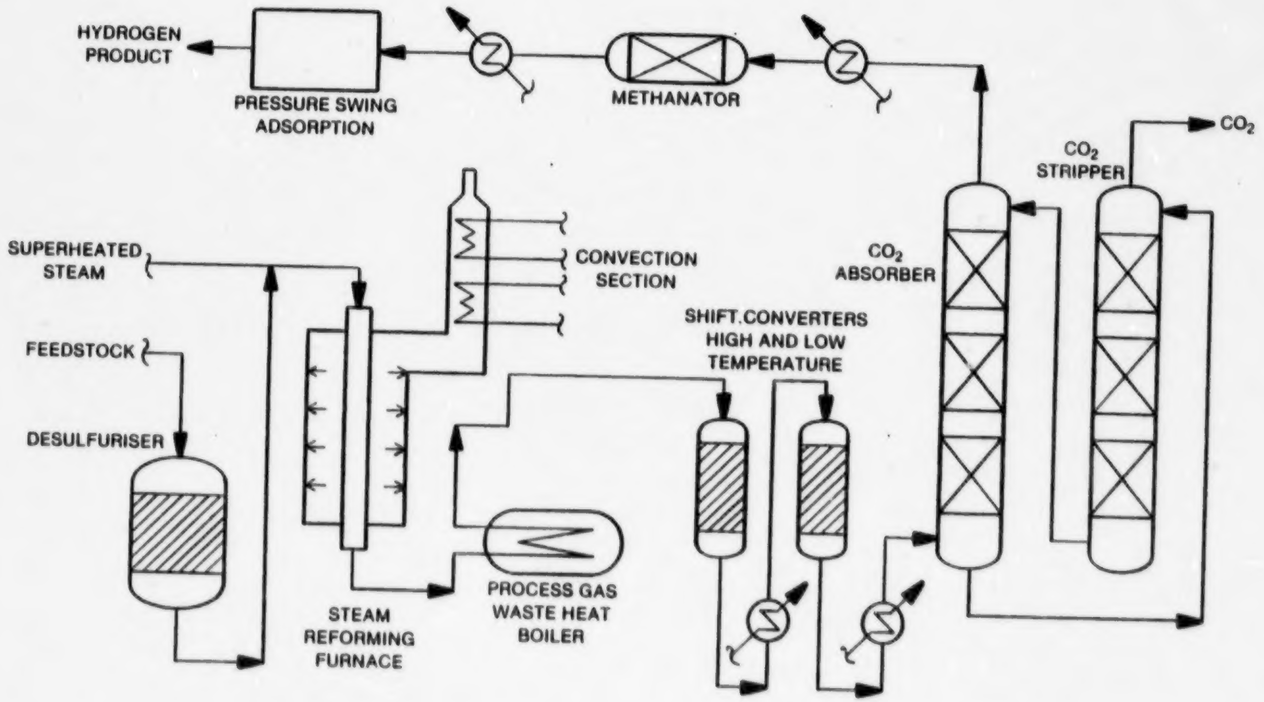

HYDROGEN PRODUCT
PRESSURE SWING ADSORPTION
METHANATOR
CO$_2$
CO$_2$ STRIPPER
SUPERHEATED STEAM
CONVECTION SECTION
CO$_2$ ABSORBER
SHIFT.CONVERTERS HIGH AND LOW TEMPERATURE
FEEDSTOCK
DESULFURISER
STEAM REFORMING FURNACE
PROCESS GAS WASTE HEAT BOILER

Figure A.10-1. Hydrogen production by steam reforming

The hydrogen-rich gas containing carbon dioxide is then cooled and scrubbed to remove essentially all of the carbon dioxide. Any of a number of CO_2 removal processes are available, including the amine processes (such as monoethanolamine) and the Benfield activated hot carbonate process. Any remaining carbon dioxide and carbon monoxide are removed by heating the gas and passing it through a nickel base methanation catalyst where the carbon monoxide and carbon dioxide react with hydrogen to form methane. The production of one million scf of hydrogen typically requires about 280,000 scf of natural gas or 60 barrels of naphtha (A.10-2, A.10-3).

The product gas, hydrogen purities of 99+ percent (volume) can be obtained, but the usual range is 95-98 percent, with less than 10 ppm carbon oxides. Final purification to greater than 99.9 percent is usually achieved in a pressure swing adsorption (PSA) unit. In the PSA unit, impurities are adsorbed on molecular sieves.

Environmental Impact: The steam reformer furnace flue gas is the only source of emissions from the steam reforming process of hydrogen production. The amount of emissions depends on the fuel used.

Capacity Limitations: Steam reforming hydrogen plants are in operation with capacities up to 140 million scfd (A.10-3). The minimum economic size depends on the location and complex factors such as feedstock cost.

Advantages: The steam reforming process is well-developed and widely used. A large range of feedstocks can be used in the process. The capital and operating costs for steam reforming are lower than for partial oxidation.

Disadvantages: The catalysts used in the process are extremely sensitive to sulfur. The process furnace required produces emissions.

References:

A.10-1 Voogd, J. Hydrogen by Steam Reforming. Eighth World Petroleum Congress Proceedings, pp. 83-90. 1971.

A.10-2 Radian Corporation. Assessment of Atmospheric Emissions from Petroleum Refining. Prepared for the Environmental Protection Agency, EPA-600/2-80-075 a-e. July 1980.

A.10-3 "Gas Processing Handbook." Hydrocarbon Processing, pp. 161-163. April, 1982.

A.10-4 "A Fluid Way to Make Hydrogen." Chemical Weekly, 118(19, pp. 71, 75. 1976.

A.10-5 Cromeans, J. S., et al. Commercial Experience with Hydrogen Manufacturing Catalyst. American Chemical Society, Division of Petroleum Chemistry, Prepr. Series 16, Issue 2, pp. C38-C44. April, 1971.

A.10-6 Bery, R. N. Hydrogen for Refining - Design and Performance. American Chemical Society, Division of Petroleum Chemistry. Prepr. Series 16, Issue 2, pp. C67-C76. April, 1971.

A.10-7 "Hydrogen Plants - Where They Are and Where They Are Going." Oil and Gas Journal, pp. 176-182. June 21, 1971.

A.11 Technology: Partial Oxidation - Hydrogen Production

Fuels: Naphtha, high sulfur residual petroleum stocks

Status: The partial oxidation method of producing hydrogen was developed in the early 1950's. Two versions of the process exist — one licensed by Shell Development, the other by Texaco. Several hundred units have been installed, mostly overseas, where light feedstocks were scarce until the North Sea oil fields were discovered (A.11-1).

Description: The flow diagram for the Texaco Synthesis Gas Generation Process is given in Figure A.11-1. Large quantities of hydrogen can be generated by the partial oxidation process at any selected pressure up to 160 atmospheres. The use of fuel-fired heaters is minimized. The hydrogen sulfide produced from high sulfur residual petroleum feedstocks can be recovered in the sulfur recovery unit.

The residual fuel oil is first partially combusted with oxygen in the presence of steam. The combustion is exothermic and non-catalytic. The synthesis gas produced is composed of hydrogen and carbon monoxide. Small amounts of carbon dioxide, hydrogen sulfide, methane, carbonyl sulfide, and soot are also present.

The soot is removed in a water quench tower. A selected soot level is maintained in the circulating water system by withdrawing a portion of the water and contacting it with naphtha. The carbon is transferred to the naphtha phase. The water and naphtha are separated in a decanter, and the water is returned to the circulating system. The naphtha-carbon mixture is then mixed with a portion of the residual oil feed to the generator. The naphtha is recovered by distillation, and the soot is transferred to the generator feed.

The combustion chamber gas exits at about 2000° to 2800°F. It is quenched with hot water and simultaneously saturated with steam before being fed to a shift converter. In the shift converter, carbon monoxide is

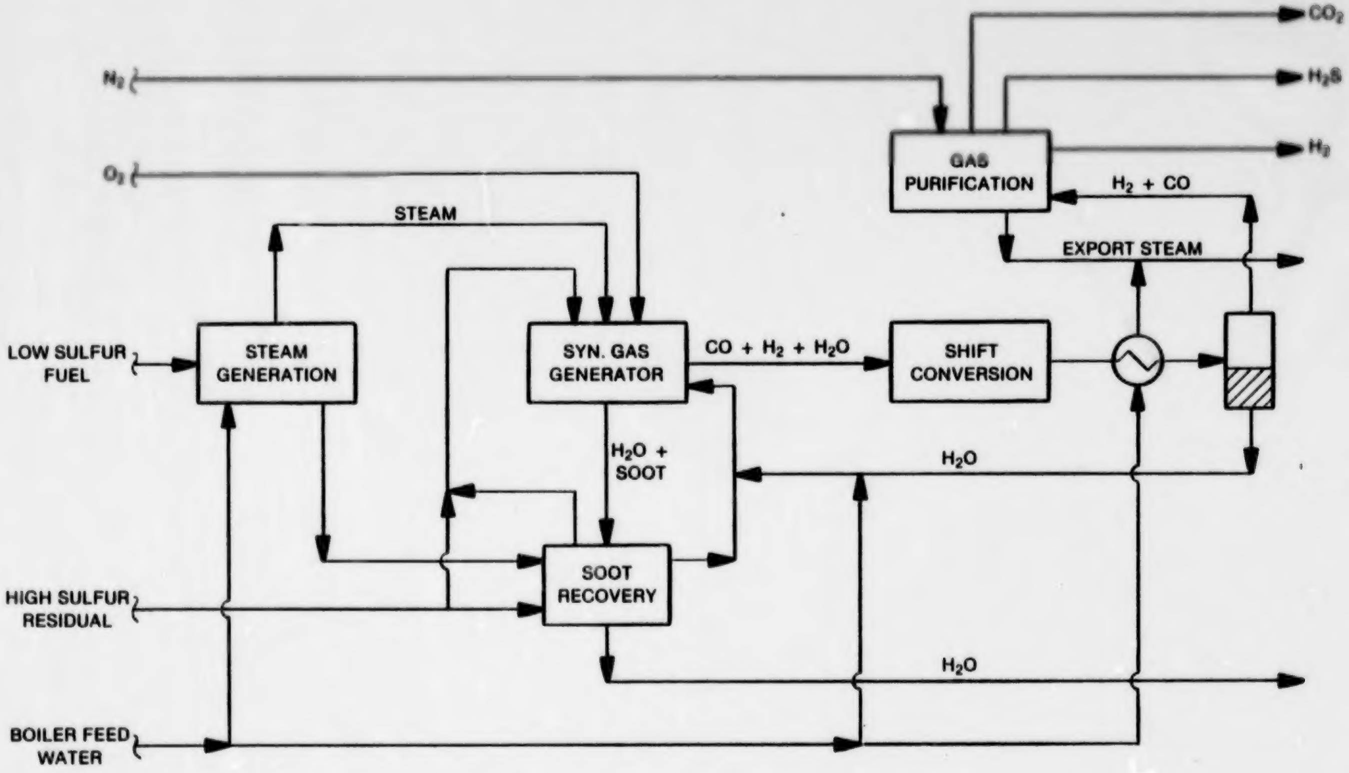

N_2
O_2
LOW SULFUR FUEL
HIGH SULFUR RESIDUAL
BOILER FEED WATER
STEAM GENERATION
STEAM
SYN. GAS GENERATOR
H_2O + SOOT
SOOT RECOVERY
CO + H_2 + H_2O
SHIFT CONVERSION
GAS PURIFICATION
CO_2
H_2S
H_2
H_2 + CO
EXPORT STEAM
H_2O
H_2O

Figure A.11-1. Hydrogen production by partial oxidation

converted to carbon dioxide and additional hydrogen over a cobalt-molybdenum catalyst by the water gas shift reaction.

Gas from the shift converter is primarily hydrogen and carbon dioxide with lesser amounts of carbon monoxide, methane, and hydrogen sulfide. The carbon dioxide and hydrogen sulfide must be removed. A number of commercial processes are available for this separation. One of these, the Rectisol process, uses methanol at temperatures of -50^{o} to $-60^{o}F$ to separate the CO_2 and H_2S from the hydrogen-rich gases. H_2S levels in the H_2-rich stream of less than 1 to 5 ppm can be obtained. The hydrogen-rich stream produced generally contains 95 to 98 percent H_2 (A.11-2, A.11-3).

Environmental Impact: The only air emissions from the partial oxidation process come from the combustion products the steam generator produces while supplying high pressure steam to the generator and soot recovery system (A.11-3). Specific emissions will depend on the type of steam generator and fuel. Various solid wastes are also produced, some of which may be classified as hazardous.

Capacity Limitations: The maximum size is assumed to be about the same as for steam reforming hydrogen production plants - 140 million scfd.

Advantages: The partial oxidation process for hydrogen production has the capability of using high sulfur residual petroleum feedstocks in an environmentally acceptable manner. Net export steam is produced by the process.

Disadvantages: The capital and operating costs are higher for partial oxidation than for steam reforming.

References:

A.11-1 "A Fluid Way to Make Hydrogen." Chemical Weekly, 118(19), pp. 71-75. 1976.

A.11-2 Radian Corporation, *Assessment of Atmospheric Emissions for Petroleum Refining*, Prepared for the Environmental Protection Agency, EPA-600/2-80-075 a-e, July 1980.

A.11-3 Schlinger, W. G., and W. L. Slater. "Partial Oxidation - A Minimum Pollution Route for Hydrogen Manufacture", 16(2), Texaco, Inc., American Chemical Society, Division of Petroleum Chemistry, pp. C45-C50. April, 1971.

A.12 Technology: Coal Gasification

Fuel: Coal

Status: Coal gasification technology has been known for over 100 years. By the mid 1920's an estimated 11,000 coal gasifiers were in operation in the U. S. alone. When cheap natural gas became widely available after World War II, the majority of the coal gasifiers were retired and gasification technology went dormant for many years. The Federal government began programs in the 1960's to improve gasification systems which would be more widely used than those on the market. The main emphasis of these programs was the development of processes for the production of high-Btu gas which could be used to supplement natural gas supplies used for home heating.

Only low and medium Btu gasification processes are currently operating on a commercial scale. Several high-Btu gasification plants were planned, but most have been cancelled. One high-Btu plant, however, is currently in startup. There are a number of gasification pilot plants in operation.

The following coal gasification processes have either been in operation or are considered currently ready for commercial design and operation (A.12-1, A.12-2):

- Chapman (Wilputte)
- Koppers-Totzek
- Lurgi
- Wellman-Galusha
- Wellman Incandescent
- Winkler
- Woodhall-Duckham/Gas Integrale
- Kohlegas Nordrhein GmbH
- Westinghouse
- KBW Water Jacket/Tubular
- Saarberg/Otto
- Shell-Koppers

- Texaco
- U-Gas
- Kiln Gas

Coal gasification plants may be used to produce low, medium, or high Btu gases which can then be used directly or exported. The product gas could be combusted in combined cycle turbines for power generation as currently being demonstrated at the Cool Water facility in California. Shifted product gases, high in hydrogen, could be used with fuel cells to produce electricity, or purified to yield a hydrogen product. A number of other chemicals (such as methanol, ammonia, or various petrochemical feedstocks) are either currently being produced from coal gasification product gases or are planned to be produced from coal gasification plants in the future. At least one plant has been proposed to supply multiple products. A flow diagram for this plant, proposed for the Kennedy Space Center, is shown in Figure A.12-1. Because its products include several commodities (liquid hydrogen and nitrogen) and electrical power, this plant concept has been called polygeneration.

The majority of gasification systems consist of four operations: coal pretreatment, coal gasification, raw gas cleaning, and gas benification. Raw gas cleaning may sometimes be avoided depending on the gasification process used and the end use of the gas.

Generally, any coal is capable of being gasified if the proper pretreatment is employed. The necessary treatment depends on the type of coal and the specific gasification process. With high moisture coals, coal drying may be desirable. Partial oxidation may be employed to simplify gasifier operation for caking coals. Fixed-bed gasifiers require a sized coal, while pulverized coal is required for fluid or entrained-bed gasifiers. In the Texaco gasification process, pulverized coal is slurried with water before it is fed to the gasifier.

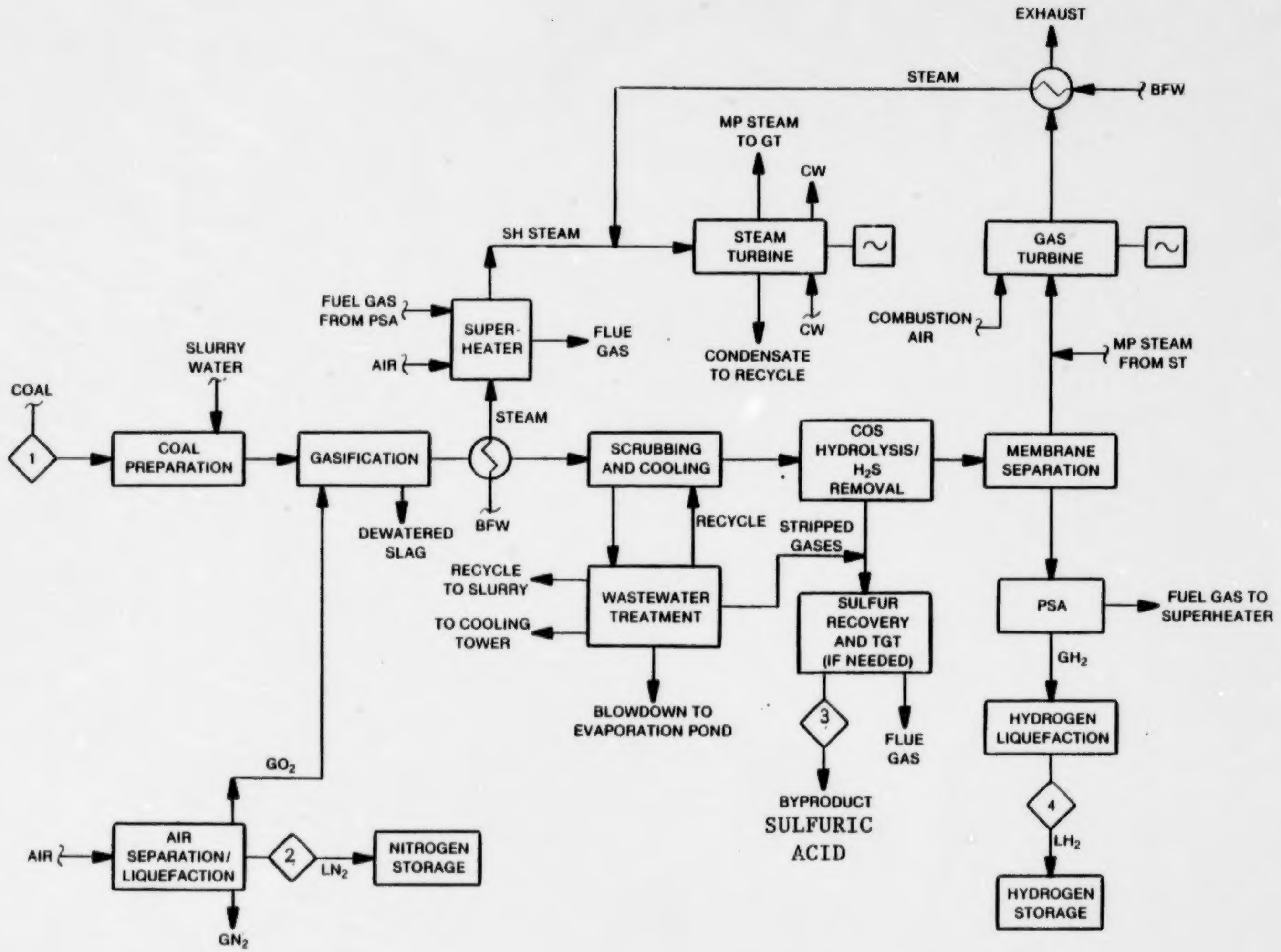

EXHAUST
STEAM
BFW
MP STEAM TO GT
CW
SH STEAM
STEAM TURBINE
GAS TURBINE
FUEL GAS FROM PSA
SUPER-HEATER
FLUE GAS
CW
COMBUSTION AIR
AIR
CONDENSATE TO RECYCLE
MP STEAM FROM ST
SLURRY WATER
COAL
STEAM
1
COAL PREPARATION
GASIFICATION
SCRUBBING AND COOLING
COS HYDROLYSIS/ H_2S REMOVAL
MEMBRANE SEPARATION
DEWATERED SLAG
BFW
RECYCLE
STRIPPED GASES
RECYCLE TO SLURRY
WASTEWATER TREATMENT
TO COOLING TOWER
SULFUR RECOVERY AND TGT (IF NEEDED)
PSA
FUEL GAS TO SUPERHEATER
GH_2
BLOWDOWN TO EVAPORATION POND
3
FLUE GAS
HYDROGEN LIQUEFACTION
GO_2
BYPRODUCT SULFURIC ACID
4
LH_2
AIR
AIR SEPARATION/ LIQUEFACTION
2
LN_2
NITROGEN STORAGE
HYDROGEN STORAGE
GN_2

Figure A.12-1. Flow diagram for coal gasification polygeneration plant

Carbon, hydrogen, and oxygen are the three primary ingredients needed to produce synthesis gas. Coal provides the carbon; steam usually provides the majority of the hydrogen; and oxygen is supplied either as air or pure oxygen. Pure oxygen produces medium-Btu gas while air produces low-Btu gas. Heat is supplied to the process by either combusting a portion of the coal in the gasifier, or by hot pebbles or ceramic balls from an external source. Carbon monoxide, methane, and hydrogen are the three major combustible gases produced from coal gasification. Hydrogen content can range from 20-35 percent depending on the process and operating conditions selected.

Four major concepts for coal gasification have been developed: fixed bed, fluidized-bed, entrained-flow, and underground gasification. Underground gasification is generally only used on coals that are economically or technically unattractive for mining. Since it is assumed that coal would be gasified on-site, a description of underground gasification will not be given.

After pretreatment, coal is fed into the top of a fixed-bed gasifier. The coal moves slowly downward in a bed countercurrent to a stream of air or oxygen. The countercurrent contact allows the coal gas gaseous reactants to be preheated before gasification. Gasification occurs lower in the bed with ash falling through the coal grate. Long residence times produce low gasification rates, but the carbon conversion is high which translates into high thermal efficiencies. Caking coals require either pretreatment or a stirrer in the bed section to prevent agglomeration.

In fluidized-bed gasifiers, smaller particles of coal are used. The particles are fluidized by the upward moving air or oxygen stream. The smaller particles and fluidized bed promotes faster gasification rates due to the increased surface area available for chemical reactions. Carryover of entrained solids can lead to fuel loss and make solids removal from the raw gas more difficult. However, less soot and tar is produced which simplifies gas cleanup. Coal caking can be a problem, but not to the extent seen in fixed-bed gasifiers.

In entrained-flow gasifiers, pulverized coal, air (or oxygen), and steam are premixed and fed to the gasifiers through burners or nozzles. The flow of reactants is cocurrent requiring higher temperatures due to the decreasing reaction rate as the reactants pass through the reactor. High exit temperatures require a heat recovery system to improve thermal efficiency. All types of coal can be used in the entrained-flow gasification process. Reaction rate and throughput per unit volume are higher because of the coal particle size. Tar production is minimal. Disadvantages of the entrained-flow gasifier include large carryover of fine particles, short refractory life, unreliable coal feeding, and the need for a heat recovery system. One of the leading entrained flow processes, the Texaco gasifier, uses a water slurry feed system to deliver a pulverized coal slurry to the gasifier (50 to 70 weight percent solids). The water in the slurry supplies the hydrogen needed for gasification.

The raw gas from the gasifier contains varying concentrations of carbon monoxide, carbon dioxide, hydrogen, methane, other organics, hydrogen sulfide, miscellaneous acid gases, nitrogen (if air was used as the oxygen source), particulates and water. Four gas purification processes may be required to prepare the gas for combustion or further beneficiation: particulate removal, tar and oil removal, gas quenching and cooling, and acid gas removal. The primary function of the particulate removal process is the removal of coal dust, ash and tar aerosols in the raw product gas. During tar and oil removal and gas quenching and cooling, tars and oils are condensed, and other impurities such as ammonia are scrubbed from raw product gas using either aqueous or organic scrubbing liquors. If the raw gas is relatively free of particulates and tars, heat recovery systems may be used to replace part of the gas cooling/quenching system. Gases such as H_2S, COS, CS_2, mercaptans, and CO_2 can be removed by an acid gas removal process. These processes generally absorb the acid gases in a solvent, from which they are subsequently stripped, forming a nearly pure acid gas waste stream with some hydrocarbon carryover. At this point, the raw gas is classified as either a low-Btu or medium-Btu gas.

To produce high-Btu gas, the heating value of the medium-Btu gas is raised by shift conversion and methanation. In the shift conversion process, H_2O and a portion of the CO are catalytically reacted to form CO_2 and H_2. After passing through an absorber for CO_2 removal, the remaining CO and H_2 in the product gas are reacted in a methanation reactor to yield CH_4 and H_2O. In the production of rich hydrogen gases, shift converters would typically be used but a methanation step would be omitted.

There are also many auxiliary processes accompanying a coal gasification facility, which provide various support functions. These auxiliary processes include the oxygen plant, power and steam plant, sulfur recovery unit, water treatment plant, and cooling towers.

Environmental Impact: Emissions from a gasification process can vary depending on the type of coal used and the specific gasification process. The addition of an integrated power-producing facility will also affect emissions. Air emissions are generally well controlled unless the product gas is combusted. A number of solid wastes such as slag and spent catalysts will also be produced; these wastes could require handling and disposal as hazardous wastes.

Capacity Limitations: Integrated gasifier combined-cycle plants range in size from 10 MW to a projected 1000 MW plus. However, capital costs for the smaller plants are probably prohibitive, and the smaller plants are also likely to be relatively less efficient.

Advantages: Coal gasification features use of a fuel with an assured long-term supply. Cogeneration of steam and electricity is possible. In addition, hydrogen gas can be produced from coal gasification.

Disadvantages: An integrated gasifier combined-cycle plant requires a fairly complex plant, especially when compared to some of the more common technologies such as internal combustion engines or conventional boilers.

Overall system efficiency is lower than other power generating systems due to the required gas cooling.

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A.13 Technology: Electrolysis Production of Hydrogen

Fuels: Electricity

Status: Three types of water electrolyzers are currently available commercially; the unipolar (tank) electrolyzer, the bipolar (filter-press) electrolyzer, and the solid polymer electrolyte (SPE) electrolyzer. These cells are available from Teledyne Isotopes, General Electric Company, Life Systems, Inc., The Electrolyser Corporation (Canada), De Nor S. p. A. (Italy), and Lurgi GmbH (Germany) (A.13-1).

Hydrogen production by electrolysis is used mostly for small volume production due to the large electrical requirements. More economic options are available for large scale production (e.g., steam reforming, partial oxidation).

Description: Electrolytic production of hydrogen is the simplest and cleanest method available for producing hydrogen from water. Electrolyzers break water down and provide for physical separation of the products, hydrogen and oxygen, at purities of approximately 99.9 and 99.7 percent, respectively. No by-products are formed and essentially no moving parts are involved.

Electrolysis of water in a perfectly efficient cell requires 94 kWh of electrical energy for each 1000 scf of hydrogen produced. Of the 94 kWh, only 79 kWh are required as electrical energy with the balance required as heat. Efficiency in most cells approaches 100% since no alternate chemical reactions can occur except the recombination of hydrogen and oxygen in solution.

Hydrogen can be produced at voltages as low as 1.23 V. However, this reaction is endothermic and would require the absorption of heat from the surroundings. Isothermal generation of hydrogen and oxygen at $77^{o}F$ requires 1.47 V with no waste heat produced at 100% thermal efficiency. However, the hydrogen production rate at 1.47 V is very slow. Most electrolyzers use operating voltages of 1.7-2.2 V/cell to decompose water at a reasonable rate.

Current electrolyzer technology achieves efficiencies of approximately 80% based on input electricity to the higher heating value of hydrogen.

The first industrial application of water electrolysis utilized unipolar (tank) electrolyzers. The tank electrolyzers consist of a series of electrodes, anodes and cathodes alternately, suspended vertically and parallel to one another in a tank. The tank is usually filled with a 20-30 percent solution of potassium hydroxide (KOH) in water which acts as an electrolyte. Every other electrode, usually the cathode, is enclosed by a diaphragm which is impermeable to gas, but permeable to the cell's electrolyte. Asbestos is the most common diaphragm material. The whole electrode assembly is hung from a series of gas collectors. A single tank-type cell will contain several electrodes with electrodes of the same polarity connected in parallel. An individual tank will operate across a 1.9-2.5 V d.c. supply. Individual tank units are connected either in series or parallel as modules. A schematic of a tank-type electrolyzer is presented in Figure A.13-1. Tank-type electrolyzers have the following advantages:

- relatively few parts are required and those needed are relatively inexpensive, and
- individual cells can be isolated for repair/replacement by short circuiting the two adjacent cells.

Disadvantages are:

- high current densitites can not be handled because of cheaper component parts, and
- inability to operate at high temperatures because of heat loss from the large surface area of the connected cells.

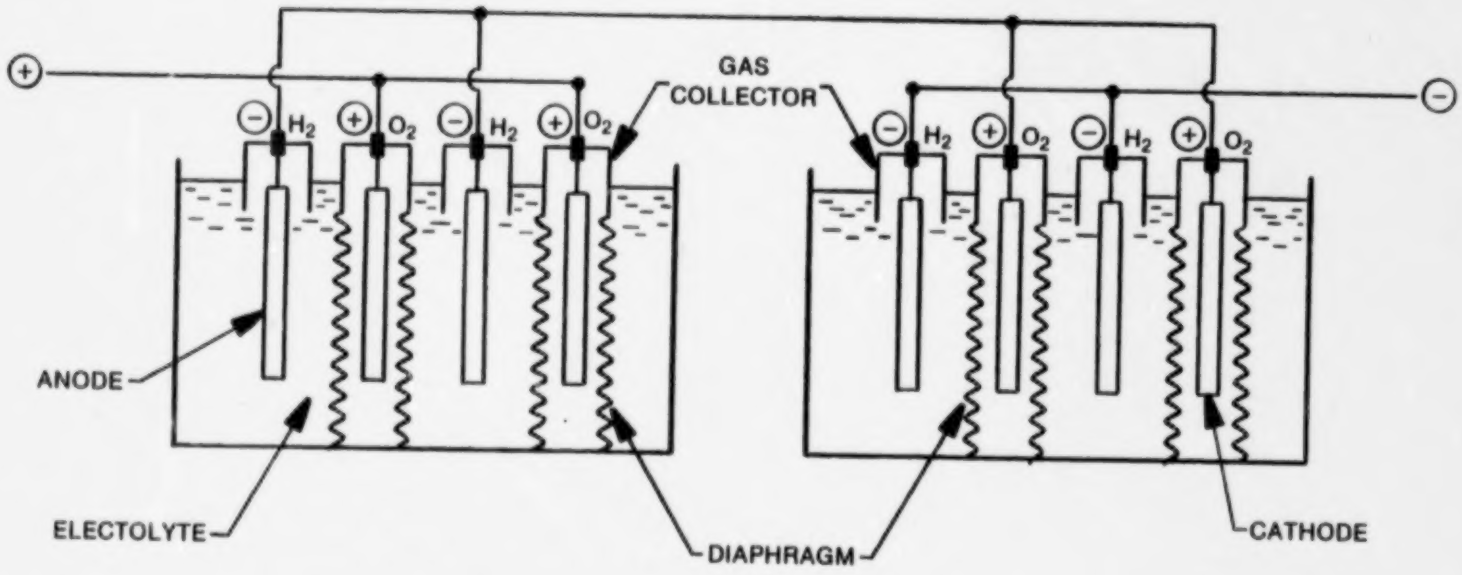
GAS COLLECTOR
H_2
O_2
H_2
O_2
H_2
O_2
H_2
O_2
ANODE
ELECTOLYTE
DIAPHRAGM
CATHODE

Figure A.13-1. Tank electrolyzer schematic

The bipolar (filter-press) electrolyzer combines the anode and cathode on a single electrode. One side of each electrode functions as an anode in one cell and the other side of the electrode as a cathode in the next cell. The electrolyte is a 20-30 percent KOH/water solution. The filter-press electrolyzer gains its name from its resemblance to a filter-press as shown in Figure A.13-2. Alternating layers of electrodes and diaphragms are clamped together. Diaphragms are used between the electrodes to keep the hydrogen and oxygen separate. The cells are connected in series. The total voltage required is the sum of each cell voltage, which is about 2 V/cell. Large gas output can be achieved from small plant sizes since the cells can be made relatively thin. This results in a lower current than is required in a tank-type electrolyzer. Filter-press electrolyzers are also more suited to high pressure operation. This design is used by the majority of electrolyzer manufacturers. The disadvantage of filter-press electrolyzers results from the configuration. If a single electrode or diaphragm breaks down, the whole group of cells has to be shut down. Repairs are difficult and require a considerable amount of time.

The solid polymer electrolyte (SPE) electrolyzers are usually configured in the filter-press layout. The electrolyte consists of a thin, solid, plastic sheet of perfluorinated sulfonic acid polymer. Ionic conductivity is supplied by mobile hydrated hydrogen ions (H^+H_2O) which move through the solid electrolyte by passing from one sulfonic acid group to another. The electrolyte can withstand pressure differences of up to 1000 psi. The electrode is either integrally imbedded in the surface of the electrolyte or takes the form of a sheet of metal sandwiched between the solid electrolyte material. SPE electrolyzers utilize very thin electrolyte materials. This requires less space than either tank-type or filter-press electrolyzers. Another advantage is that the electrolyte is captive since it is solid and can not be lost from the cell.

Environmental Impact: Electrolyzers do not involve any reactions except the decomposition of water and possible recombination of hydrogen and oxygen

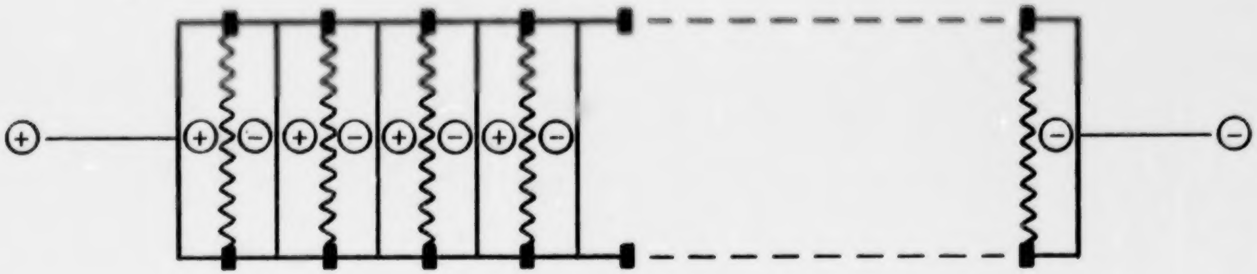

Figure A.13-2. Filter press electrolyzer schematic

to form water. The only possible emissions associated with electrolysis comes from the generation of the required electricity.

Capacity Limitations: The modular nature of electrolyzers allows the construction of virtually any size plant. This also allows capacity to be added as the demand increases.

Advantages: Electrolyzers produce hydrogen and oxygen at high purities without producing any by-products. The raw material, water, is readily available and cheap. The modular nature allows the construction of any size plant and the ability to add capacity as demand increases.

Disadvantages: Electrolyzers utilize large quantities of electricity. The overall efficiency, fuel-to-electricity-to-hydroge, ranges from 21-32 percent if the electricity is generated by conventional fossil-fuel fired means. This compares to overall efficiencies of hydrogen production by steam reforming and coal gasification of 70 percent and 60-65 percent, respectively (A.13-3).

References:

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A.13-2 Sprafka, R. J., et al. Study of Systems and Technology for Liquid Hydrogen Production Independent of Follis Fuels. E:F Technology, Inc. under Contract No. NAS10-10541.

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A.14 Technology: Hydrogen Liquefaction

Status: Hydrogen liquefaction is a well-developed technology. However, there is not a great demand for liquid hydrogen and only seven plants are currently operating in the United States. The size of these plants ranges from 6 to 30 TPD.

Description: Three different techniques are commonly used to liquefy hydrogen for large scale operations. The first is the Joule-Thomson expansion in which compressed hydrogen is throttled to a lower pressure through a nozzle or valve. This is an adiabatic process which usually results in a temperature reduction of the throttled gas. In the case of hydrogen, temperature reduction only occurs if the gas has been precooled to below its inversion temperature of 204K. Hydrogen cannot be liquefied solely by this refrigeration technique.

The second technique is the use of an auxiliary refrigerating fluid such as liquid and gaseous nitrogen. Liquid nitrogen can provide the necessary precooling to permit liquefaction of the hydrogen via Joule-Thomson expansion.

The third technique is work expansion of compressed hydrogen to a lower pressure by means of an expansion engine. In a perfectly efficient engine, this is an isentropic process which results in a reduction in enthalpy of the expanding gas. The work which results from the expansion is rejected from the process via the engine shaft and is recoverable for external use. Expansion engines may be either reciprocating or centrifugal, but economics favor centrifugal turbines in large scale use. An electric generator coupled to the shaft can be used to recover energy.

An important consideration in the liquefaction of hydrogen is the ortho-para composition. Hydrogen exhibits a quantum effect in the cryogenic region. The two different types of hydrogen are characterized by a difference in the relative orientation of the nuclear spin of the two atoms which comprise the molecule. Symmetric spins are referred to as ortho hydrogen;

asymmetric spins are designated para hydrogen. Para hydrogen molecules possess a lower minimum energy state than ortho hydrogen. The composition of hydrogen is an equilibrium function of temperature. At temperatures above about 300 K (80.6oF), hydrogen gas consists of 25 percent para and 75 percent ortho hydrogen molecules. This mixture is known as normal hydrogen. The equilibrium composition at hydrogen's atmospheric boiler point (20.39 K) is 99.79 percent para. The conversion from ortho to para releases 609 Btu/lb-mol. The heat of vaporization of normal hydrogen is only 385 Btu/lb-mol. The conversion of hydrogen from ortho to para occurs spontaneously at a slow rate. The conversion is a second order reaction with an initial rate of about 1 percent per hour. The resulting boiloff amounts to about 18 percent after one day and about 50 percent after one week. Storage of liquid hydrogen with greater than 5 percent ortho content would result in high storage losses from the heat conversion. To minimize hydrogen storage losses from this conversion, hydrogen liquefiers are equipped with catalytic reactors to accelerate the reaction and produce a liquid hydrogen product which has a high para content, usually 95 percent or greater.

A typical hydrogen liquefaction process is depicted in Figure A.14-1. Three distinct process streams exist; a product stream, a hydrogen recycle stream, and a cold nitrogen stream. The latter two streams provide the refrigeration of the product stream. Nitrogen provides refrigeration at the 80 K level and warmer. The recycle stream supplies refrigeration needed below 80 K via work expansion using turbines at two temperature levels and a Joule-Thomson throttling for final cooling of the product.

Feed hydrogen is compressed and mixed with the compressed recycle stream. The feed hydrogen must contain less than 1 ppm impurities to prevent plugging at heat exchanger passages and equipment damage from solidification of other gases. The hydrogen stream is precooled to nearly liquid nitrogen temperature and divided before further cooling in a liquid nitrogen bath. The product stream passes through a catalytic converter which converts the hydrogen to approximately 45 percent para concentration. It is further cooled against

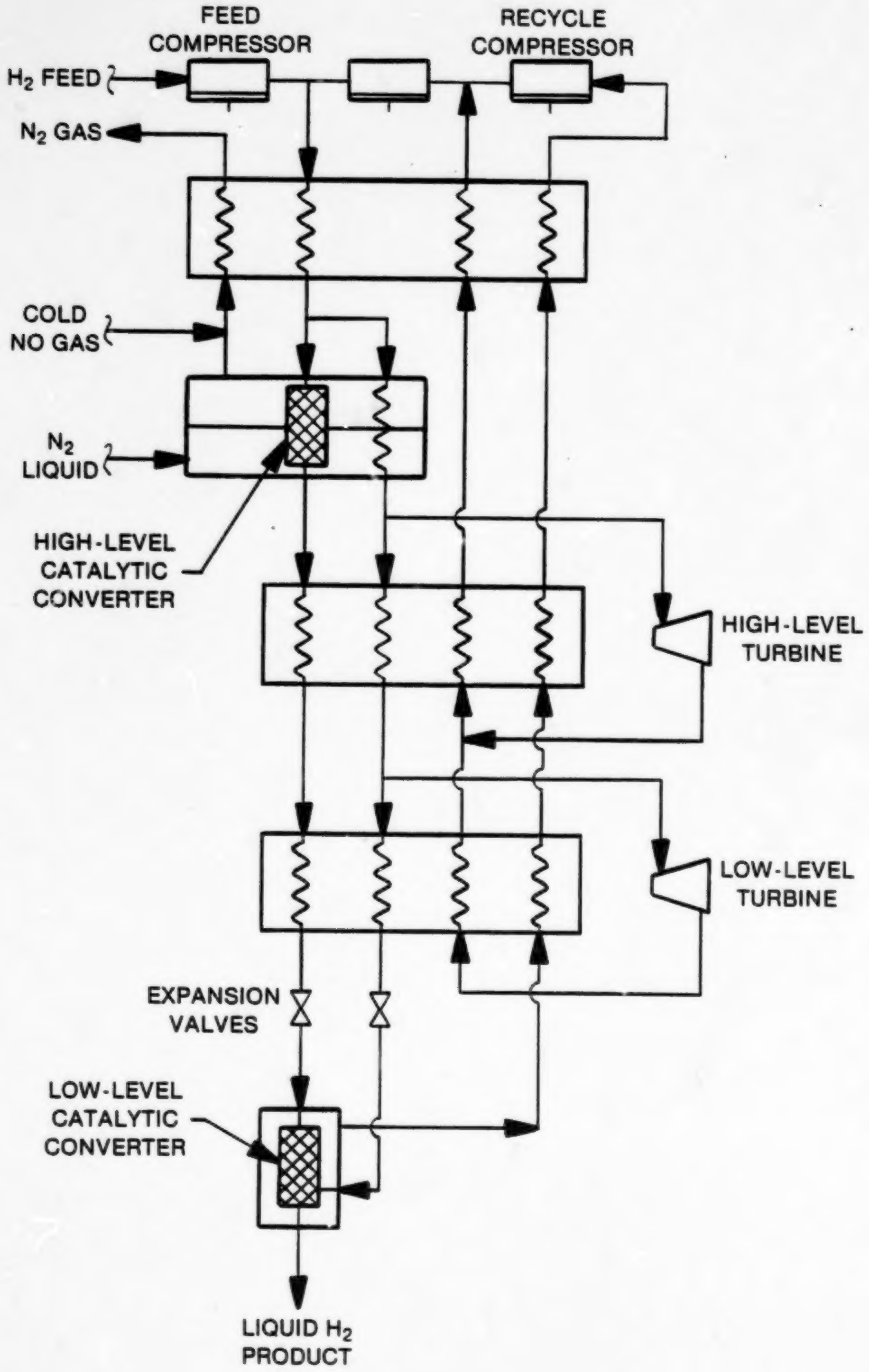
FEED COMPRESSOR
RECYCLE COMPRESSOR
H_2 FEED
N_2 GAS
COLD NO GAS
N_2 LIQUID
HIGH-LEVEL CATALYTIC CONVERTER
HIGH-LEVEL TURBINE
LOW-LEVEL TURBINE
EXPANSION VALVES
LOW-LEVEL CATALYTIC CONVERTER
LIQUID H_2 PRODUCT

Figure A.14-1. Flow diagram for hydrogen liquefaction and conversion

cold exhaust streams from the turbines followed by Joule-Thomson expansion through a valve and a final stage of cooling and conversion to at least 95 percent para hydrogen against low pressure boiling liquid hydrogen. All low pressure hydrogen streams are returned in heat exchange with the cooling streams and fed to the recycle compressor for recompression.

The ortho-to-para conversion shown is carried out in two stages. As the number of stages increases, the required work decreases until the reversible case is obtained with an infinite number of stages. The theoretical work required to liquefy normal hydrogen to 99.79 percent para ranges from 1.799 kWh/lb with the reversible process to 2.439 kWh/lb for a one-stage conversion. Actual work requirements lie in the range of 5.66 to 6.0 kWh/lb due to equipment inefficiencies (A.14-6). After studying the magnitude of various process losses and the effects of several operating parameters on the efficiency of hydrogen liquefaction, actual hydrogen liquefiers were determined to be efficient with only marginal opportunity for improvement (A.14-1, A.14-2). About 280 gpm of cooling water is required per pound of LH_2.

Environmental Impact: No local environmental impact is anticipated if the compressors are driven by electric motors.

References:

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A.15 Technology: Hydrogen Storage (Liquid, Gas)

Status: Hydrogen is currently stored above ground in both gaseous and liquid forms. Large scale storage favors liquid hydrogen over gaseous hydrogen.

Description: Gaseous hydrogen can be stored in pressure vessels at pressures as high as 2450 psig. Attemps were made in the early 1960's to store hydrogen at 5000 psig. However, the storage vessels failed in less than one year due to hydrogen embrittlement. Similar results were obtained with a pressure vessel operated at 3900 psig. Future storage of gaseous hydrogen may be underground in aquifers, mined caverns, and depleted oil and gas wells.

Liquid hydrogen storage vessels have been built that range in size from 1 liter flasks up to 900,000 gallon Dewars. Liquid hydrogen boil-off is the major factor in the storage vessel design. The performance of these storage vessels with respect to boil-off varies and depends on the type of insulation employed, vessel size and shape, and vessel structural-support considerations.

Insulations frequently used for storage of liquid hydrogen are: vacuum with a liquid-nitrogen shield, evacuated foams, evacuated perlite, and evacuated multi-layer "super insulations". The choice of insulation for a particular application is usually a compromise in which factors such as cost, ruggedness, weight, volume, and reliability are considered.

Boil-off losses from liquid hydrogen vessels are summarized in Table A.15-1, assuming a 95 percent para composition. The larger vessels prove more economical in terms of boil-off loss as well as reduced capital cost per gallon.

Liquid hydrogen storage is preferred over gaseous hydrogen storage for almost all sizes. This is due to the energy density of the two storage options. Table A.15-2 compares liquid and gaseous hydrogen storage. The

TABLE A.15-1. LH_2 STORAGE DEWAR PERFORMANCE (A.15-1)

Dewar Identification	Capacity Gal	Capacity 10^6 Btu[a]	Insulation	Boil Off %/day	Dewar wt, lb	Dewar Vol, ft^3	Btu/lb[a]	Btu/ft^3[a]	Cost[b]
Linde LSH-150	39.7	1.21	Linde SI-4(1")	2.5-3.0	166	10.7	7,300	113,000	$50/gal
Linde LSH-100	264	8.07	Linde SI-4(1.25")	1.0	2,400	158	3,370	51,000	-
Beech Transport Trailer	1,585	48.4	Powder	1.9	-	-	-	-	$12/gal
Semi-Trailer	7,800	238	Linde SI-4	0.5	32,200	1,780	7,400	134,000	-
Conventional Trailer	13,000	397	Evacuated Super Insul.	.25-.8	40,700	-	9,700	-	-
Rectangular Trailer	16,000	489	Evacuated Super Insul	0.4	40,300	-	12,100	-	-
Rail Tank	26,000	795	Evacuated Perlite	0.5	-	6,540	-	122,000	-
Nevada	50,000	1,530	Evacuated Perlite	0.18	-	-	-	-	-
Nevada	500,000	15,300	Evacuated Perlite	0.05	-	-	-	-	$2/gal
KSC	850,000	26,000	Evacuated Perlite	0.026-0.03	-	180,000	-	144,000	-

[a] Based on lower heating value of 51,600 Btu/lb

[b] 1975 dollars.

TABLE A.15-2. COMPARISON OF LIQUID AND GASEOUS HYDROGEN STORAGE

Hydrogen State	Fuel Storage Capacity 10^6 Btu	ft^3	Capital Cost[a] $\$/10^6$ Btu
Gaseous (2400 psig)	2	46	750
	50	1,140	720
Liquid	2	8.8	1,000
	50	220	300
	36,000	158,000	26

[a] 1972 dollars.

capital cost for gaseous hydrogen storage is relatively insensitive to scale-up, resulting in economic storage for only small applications.

References:

A.15-1 Cole, R. B., et al. Hydrogen Storage and Transfer. Semi-Annual Technical Report, Vol. 1, DOD Report No. N00014-75-C-0220, August, 1975.

A.15-2 Mathis, D. A. Hydrogen Technology for Energy, Noyes Data Corp., Park Ridge, NJ, 1976.

TABLE A-1. SUMMARY DESCRIPTION OF INDIVIDUAL TECHNOLOGIES

Technology	Energy Resource	Capacity Limitations	Stage of Development	Efficiency fuel to Electricity	Air Emissions	Other Emissions/ Wastes	Advantages	Disadvantages
ELECTRICAL GENERATION TECHNOLOGIES								
Conventional Fired Boilers	Coal, wood, oil, natural gas, process wastes.	1-1200 MW	Well-developed	24%	Uncontrolled SO_2-0.767 lb/10^6 Btu 0.45% sulfur coal NO_x-0.538 lb/10^6 Btu Part.-6.78 lb/10^6 Btu	Coal ash, FGD sludge or solids	Proven, reliable technology.	Emission controls required are complex and expensive.
Gas Turbines	Natural and synthetic gases, diesel methane.	4-80 MW	Well-developed	Simple cycle-25% Combined cycle (using natural gas or diesel fuel)-37%	Uncontrolled SO_2-0.000406 lb/10^6Btu NO_x-0.413 lb/10^6 Btu Part.-0.014 lb/10^6 Btu (Based on natural gas firing)	None	Proven, reliable technology. Low installed capital cost. Short lead time. Quick start up.	Requires expensive fuels.
Diesel Engines	Diesel,natural gas, some heavier fuel oils.	Up to 24 MW	Well-developed	37%	Uncontrolled SO_2-0.805 lb/10^6 Btu NO_x-12.1 lb/10^6 Btu Part.-0.865 lb/10^6 Btu	None	Proven, reliable technology. Low installed capital cost. Short lead time. Quick start up.	Requires expensive fuels. Low temperature exhaust not useful for combined cycle.
Atmospheric Fluidized Bed Combustion (AFBC) Boiler/Steam Turbine	Coal, wood, oil, natural gas, process wastes.	Largest units approximately 50 MW	First commercial use in 1973. Second generation units now commercially available.	24%	Uncontrolled SO_2-1.11 lb/10^6 Btu (0.7% sulfur coal) NO_x-0.3 lb/10^6 Btu Part.-3.44 lb/10^6 Btu.	Solid waste from coal ash & limestone used for SO_2 removal	SO_2 and NO_x can be controlled in-situ. Mixture of different fuels can be burned.	Some problems have occurred with erosion of surfaces exposed to fluidized bed.
Fuel Cells	Hydrogen-rich fuel stream & oxygen.	Modular, no limitation	Demonstration of of first commercial system (4.5 MW) currently underway.	34%	Emissions dependent on technology used to produce hydrogen-rich fuel stream.	None	Modular construction allows wide range of capacities.	Sensitive to some impurities present in fuels.
Wind Turbines	Solar	Prototype units to 4.0 MW. Commercial units 200 kW and smaller.	Small units commercially proven and in use on wind farms. Larger units still in development stage.	--	None	None	No pollution. Minimal maintenance.	Rated power production dependent on constant high-velocity wind. Some interference with radio signals has been encountered in large units.

(continued)

TABLE A-1. (continued)

Technology	Energy Resource	Capacity Limitations	Stage of Development	Efficiency fuel to Electricity	Air Emissions	Other Emissions/ Wastes	Advantages	Disadvantages
ELECTRICAL GENERATION TECHNOLOGIES (Continued)								
Photovoltaics	Solar	Modular, no limitation.	Silicon cell component expensive & inefficient. Commercial 1.0 MW plant exists with construction beginning on 16.0 MW plant.	9%	None	None	No pollution. Minimal maintenance. Very reliable. Short construction time.	Very high installed capital cost. Low efficiency.
Central Receiver (Power Tower)	Solar	Conceptual systems have been designed up to 500 MW.	Prototype 10 MW system operating. Commercial 100 MW plant planned.	15%	None	None	No emissions.	Requires clear days for direct solar radiation. Thermal cycling poses material & maintenance problems.

Technology	Feedstock(2)	Other Utilities Required	Capacity Limitations	Stage of Development	Efficiency[a]	Air Emissions	Other Emissions/ Wastes	Advantages	Disadvantages
HYDROGEN OR FUEL GAS PRODUCTION TECHNOLOGIES									
Steam Reforming	Natural gas, naphtha, light hydrocarbons.	Cooling water	Up to 140 MMscfd	Well-developed	60%	SO_2 NO_x Particulates		Large range of feedstocks suitable.	Catalysts used are very sensitive to sulfur.
Partial Oxidation	Naphtha, high sulfur residual petroleum feedstocks.	Oxygen, cooling water	Up to 140 MMscfd	Well-developed	53%	SO_2 with feedstocks containing sulfur.	Wastewater	Capable of using high sulfur residual petroleum feedstocks.	More complex and expensive than steam reforming; most similar to coal gasification.
Gasification	Coal	Oxygen, cooling water	Large size range	Low- and medium-Btu gasification practices for many years. First integrated combined cycle gasification plant in startup.	50%	SO_2	Both solid & water wastes	Long term supply of fuel assured.	Long lead time. Possible production of environmentally hazardous wastes. Complex plants. Expensive product.
Electrolysis	Water	Electricity	Modular, no limitations	Commercially available, but still undergoing research for improvements.	80%	None	None	Hydrogen & oxygen produced at high purity without pollution. Cheap, readily available raw material.	High operating cost due to large electrical requirement.

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[a] For steam reforming, partial oxidation, and gasification, defined as the heating value of the hydrogen produced divided by the heating value of the feedstock. For electrolysis, defined as the heating value of the hydrogen produced divided by the electricity input.

(continued)

TABLE A-1. (continued)

Technology	Energy Resource	Capacity Limitations	Stage of Development	Efficiency	Air Emissions	Other Emissions/ Wastes	Advantages	Disadvantages
ENERGY OR HYDROGEN STORAGE TECHNOLOGIES								
Pumped Hydro	Gravity	10-2,000 MW	Well-developed	70%	None	None	Long life (>50 yrs). No pollution. Black start capability.	Surface reservoirs required. Long construction period.
Liquid, Gas Storage	NA	Up to 850,000 gal. LH_2	Well-developed	NA	None	None	Boiloff of LH_2 occurs during storage.	Proven, reliable technology. LH_2 storage better than GH_2 storage for large quantities due to size of storage vessels.
COMMODITIES PRODUCTION								
							Utilities Required	
Hydrogen Liquefaction		6-30 TPD	Well-developed	$\sim$6kWh/lb LH_2	None	None	Cooling water, electricity, steam.	
Air Separation LO_2+LN_2		Up to 2200 TPD O_2, N_2 variable	Well-developed	$\sim$0.38kWh/lb LO_2 $\sim$0.42kWh/lb LN_2	None	None	Cooling water, electricity.	

APPENDIX B

COMPLETE RESULTS OF ECONOMIC ANALYSES

TABLE B-1. COMPLETE RESULTS OF ECONOMIC ANALYSES[1]

			$ Millions (January 1992 $)	
Production Technology	Case Description	Capacity	Total Capital Investment	Net Present Value[2]
ELECTRICITY PRODUCTION				
Boiler/Steam Turbine				
• Natural gas	Baseline[3]	13.5 MW	12	-199
	Baseline[3]	15 MW	37	-219
	Baseline[3]	20 MW	43	-277
	Single Unit[4]	10 MW	24	-148
	Single Unit[4]	15 MW	31	-209
	Single Unit[4]	20 MW	38	-270
• No. 2 fuel oil	Baseline[3]	13.5 MW	36	-202
	Baseline[3]	15 MW	38	-220
	Baseline[3]	20 MW	44	-277
	Single Unit[4]	10 MW	24	-150
	Single Unit[4]	15 MW	32	-210
	Single Unit[4]	20 MW	39	-270
• No. 6 fuel oil	Baseline[3]	13.5 MW	43	-120
	Baseline[3]	15 MW	46	-129
	Baseline[3]	20 MW	51	-151
	Single Unit[4]	10 MW	28	-87
	Single Unit[4]	15 MW	37	-115
	Single Unit[4]	20 MW	45	-141
• Stoker coal	Baseline[3]	13.5 MW	55	-92
	Baseline[3]	15 MW	59	-98
	Baseline[3]	20 MW	68	-110
	Single Unit[4]	10 MW	38	-66
	Single Unit[4]	15 MW	51	-84
	Single Unit[4]	20 MW	62	-99
• AFBC coal	Baseline[3]	13.5 MW	62	-102
	Baseline[3]	15 MW	67	-108
	Baseline[3]	20 MW	78	-121
	Single Unit[4]	10 MW	43	-72
	Single Unit[4]	15 MW	57	-92
	Single Unit[4]	20 MW	70	-109
Gas Turbine				
• Natural gas	Baseline[3]	13.5 MW	31	-198
	Baseline[3]	15 MW	34	-219
	Baseline[3]	20 MW	40	-284
	Single Unit[4]	10 MW	22	-148
	Single Unit[4]	15 MW	30	-215
	Single Unit[4]	20 MW	38	-282

TABLE B-1. (continued)

Production Technology	Case Description	Capacity	$ Millions (January 1992 $)	
			Total Capital Investment	Net Present Value[2]
• No. 2 fuel oil	Baseline[3]	13.5 MW	29	-188
	Baseline[3]	15 MW	31	-207
	Baseline[3]	20 MW	37	-269
	Single Unit[4]	10 MW	20	-140
	Single Unit[4]	15 MW	28	-204
	Single Unit[4]	20 MW	35	-267
Combined Cycle Turbines				
• Natural gas	Baseline[3]	13.5 MW	35	-110
	Baseline[3]	15 MW	38	-119
	Baseline[3]	20 MW	45	-147
	Single Unit[4]	10 MW	25	-83
	Single Unit[4]	15 MW	33	-113
	Single Unit[4]	20 MW	41	-143
• No. 2 fuel oil	Baseline[3]	13.5 MW	33	-91
	Baseline[3]	15 MW	35	-98
	Baseline[3]	20 MW	42	-119
	Single Unit[4]	10 MW	23	-70
	Single Unit[4]	15 MW	31	-93
	Single Unit[4]	20 MW	38	-115
• No. 6 fuel oil (via partial oxidation)	Baseline[3]	15 MW	234	-374
	Baseline[3]	20 MW	224	-356
	Single Unit[4]	10 MW	125	-208
	Single Unit[4]	15 MW	160	-259
	Single Unit[4]	20 MW	190	-303
• Coal	Baseline[3]	15 MW	213	-311
	Baseline[3]	20 MW	226	-370
	Single Unit[4]	10 MW	135	-203
	Single Unit[4]	15 MW	174	-252
	Single Unit[4]	20 MW	208	-293
Diesels	Baseline[5]	10 MW	21	-70
	Baseline[5]	15 MW	28	-97
	Baseline[5]	20 MW	34	-124
	Multiple Units[6]	10 MW	28	-76
	Multiple Units[6]	15 MW	37	-105
	Multiple Units[6]	20	45	-134

(continued)

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TABLE B-1. (continued)

Production Technology	Case Description	Capacity	$ Millions (January 1992 $)	
			Total Capital Investment	Net Present Value[2]
• No. 2 fuel oil	Baseline[3]	13.5 MW	29	-188
	Baseline[3]	15 MW	31	-207
	Baseline[3]	20 MW	37	-269
	Single Unit[4]	10 MW	20	-140
	Single Unit[4]	15 MW	28	-204
	Single Unit[4]	20 MW	35	-267
Combined Cycle Turbines				
• Natural gas	Baseline[3]	13.5 MW	35	-110
	Baseline[3]	15 MW	38	-119
	Baseline[3]	20 MW	45	-147
	Single Unit[4]	10 MW	25	-83
	Single Unit[4]	15 MW	33	-113
	Single Unit[4]	20 MW	41	-143
• No. 2 fuel oil	Baseline[3]	13.5 MW	33	-91
	Baseline[3]	15 MW	35	-98
	Baseline[3]	20 MW	42	-119
	Single Unit[4]	10 MW	23	-70
	Single Unit[4]	15 MW	31	-93
	Single Unit[4]	20 MW	38	-115
• No. 6 fuel oil (via partial oxidation)	Baseline[3]	15 MW	234	-374
	Baseline[3]	20 MW	224	-356
	Single Unit[4]	10 MW	125	-208
	Single Unit[4]	15 MW	160	-259
	Single Unit[4]	20 MW	190	-303
• Coal	Baseline[3]	15 MW	213	-311
	Baseline[3]	20 MW	226	-320
	Single Unit[4]	10 MW	135	-203
	Single Unit[4]	15 MW	174	-252
	Single Unit[4]	20 MW	208	-293
Diesels	Baseline[5]	10 MW	21	-70
	Baseline[5]	15 MW	28	-97
	Baseline[5]	20 MW	20	-124
	Multiple Units[6]	15 MW	37	-105
	Multiple Units[6]	20 MW	45	-134

(continued)

TABLE B-1. (continued)

Production Technology	Case Description	Capacity	$ Millions (January 1992 $)	
			Total Capital Investment	Net Present Value[2]
Fuel Cells				
• Natural gas (via steam reforming)	Baseline[3]	13.5 MW	45	-118
	Baseline[3]	15 MW	49	-129
	Baseline[3]	20 MW	60	-162
	Single Unit[4]	10 MW	33	-90
	Single Unit[4]	15 MW	46	-125
	Single Unit[4]	20 MW	59	-160
• No. 6 fuel oil (via partial oxidation)	Baseline[3]	15 MW	256	-397
	Baseline[3]	20 MW	253	-386
	Single Unit[4]	10 MW	140	-225
	Single Unit[4]	15 MW	182	-283
	Single Unit[4]	20 MW	219	-333
• Coal (via gasification)	Baseline[3]	15 MW	206	-282
	Baseline[3]	20 MW	224	-292
	Single Unit[4]	10 MW	130	-184
	Single Unit[4]	15 MW	171	-230
	Single Unit[4]	20 MW	208	-268
Wind Turbines	Baseline[7]-Wind Towers 55/56[8]	10 MW	17	14
	Baseline[7]-Wind Towers 55/56[8]	15 MW	26	23
	Baseline[7]-Wind Towers 55/56[8]	20 MW	34	32
	Baseline[7]-Wind Tower 19[9]	20 MW	34	-1
	Baseline[7]-Wind Tower 14[10]	20 MW	34	-18
	50% Higher Capital Cost-WT 55/56	20 MW	51	15
	50% Lower Capital Cost-WT 55/56	20 MW	17	49
	50% Higher Non-Fuel O&M-WT 55/56	20 MW	34	21
	50% Lower Non-Fuel O&M-WT 55/56	20 MW	34	43
	50% Higher Discount Rate[11]-WT 55/56	20 MW	34	7
	50% Lower Discount Rate[12]-WT 55/56	20 MW	34	84
	50% Lower Capacity Factor-WT 55/56	20 MW	34	-11
	50% Higher Capacity Factor-WT 55/56	20 MW	34	78
	Low Electricity Prices-WT 55/56	20 MW	34	17
	High Electricity Prices-WT 55/56	20 MW	34	46
	Baseline[7]-Wind Towers 55/56	30 MW	51	51
	Baseline[7]-Wind Towers 55/56	45 MW	76	78
	Baseline[7]-Wind Towers 55/56	60 MW	100	106

(continued)

TABLE B-1. (continued)

Production Technology	Case Description	Capacity	$ Millions (January 1992 $) Total Capital Investment	Net Present Value[2]
Solar Central Receiver (Power Tower)	Baseline[7]	10 MW	46	-30
	Baseline[7]	15 MW	69	-42
	Baseline[7]	20 MW	92	-53
	50% Higher Capital Cost	20 MW	137	-109
	50% Lower Capital Cost	20 MW	47	4
	50% Higher Non-Fuel O&M	20 MW	92	-68
	50% Lower Non-Fuel O&M	20 MW	92	-37
	Low Electricity Prices	20 MW	92	-64
	High Electricity Prices	20 MW	92	-42
	50% Higher Discount Rate[11]	20 MW	93	-69
	50% Lower Discount Rate[12]	20 MW	91	-21
	50% Higher Capacity Factor	20 MW	92	-11
	50% Lower Capacity Factor	20 MW	92	-81
Solar Photovoltaics	Baseline[7]	10 MW	57	-31
	Baseline[7]	15 MW	86	-44
	Baseline[7]	20 MW	114	-58
	50% Higher Capital Cost	20 MW	170	-118
	50% Lower Capital Cost	20 MW	58	3
	50% Higher Non-Fuel O&M	20 MW	114	-64
	50% Lower Non-Fuel O&M	20 MW	114	-51
	Low Electricity Prices	20 MW	114	-69
	High Electricity Prices	20 MW	114	-46
	50% Lower Discount Rate[12]	20 MW	113	-13
	50% Higher Discount Rate[11]	20 MW	115	-80
	50% Higher Capacity Factor	20 MW	114	-16
	50% Lower Capacity Factor	20 MW	114	-86
Pumped Hydro	Baseline[7]-12 Hour Capacity	9 MW	12	--[13]
	Baseline[7]-24 Hour Capacity	9 MW	19	--[13]
	Baseline[7]-36 Hour Capacity	9 MW	26	--[13]
	Baseline[7]-48 Hour Capacity	9 MW	33	--[13]
	Baseline[7]-60 Hour Capacity	9 MW	39	--[13]
	Baseline[7]-12 Hour Capacity	15 MW	20	--[13]
	Baseline[7]-24 Hour Capacity	15 MW	31	--[13]
	Baseline[7]-36 Hour Capacity	15 MW	43	--[13]
	Baseline[7]-48 Hour Capacity	15 MW	54	--[13]
	Baseline[7]-60 Hour Capacity	15 MW	66	--[13]

(continued)

TABLE B-1. (continued)

Production Technology	Case Description	Capacity	$ Millions (January 1992 $)	
			Total Capital Investment	Net Present Value[2]
COMMODITIES PRODUCTION				
Steam Reforming of Natural Gas	Baseline	3 LPY[14]	14	-24
	Baseline	7 LPY	25	-26
	Baseline	10 LPY	32	-24
	Min. Excess Cap./Max. Cap. Factor[15]	3 LPY	11	-19
	Min. Excess Cap./Max. Cap. Factor[15]	7 LPY	19	-18
	Min. Excess Cap./Max. Cap. Factor[15]	10 LPY	25	-15
	50% Higher Capital Cost	10 LPY	49	-41
	50% Lower Capital Cost	10 LPY	17	-9
	50% Higher Non-Fuel O&M	10 LPY	33	-39
	50% Lower Non-Fuel O&M	10 LPY	33	-10
	50% Lower Discount Rate	10 LPY	33	-18
	50% Higher Discount Rate	10 LPY	33	-28
	High Fuel and Product Prices	10 LPY	33	-14
	Low Fuel and Product Prices	10 LPY	33	-37
	Commercial LH_2 Prices	10 LPY	33	43
	Commercial LH_2 Prices	7 LPY	26	21
	Commercial LH_2 Prices	3 LPY	14	-4
	Commercial LH_2 Prices/Min. Excess Cap./ Max. Cap. Factor[15]	3 LPY	11	1
Partial Oxidation of No. 6 Fuel Oil	Baseline	10 LPY	114	-137
	Baseline	7 LPY	91	-117
	Baseline	3 LPY	54	-80
	Min. Excess Cap./Max. Cap. Factor[15]	10 LPY	90	-94
	Min. Excess Cap./Max. Cap. Factor[15]	7 LPY	72	-82
	Min. Excess Cap./Max. Cap. Factor[15]	3 LPY	43	-62
Gasification of Coal	Baseline	10 LPY	113	-117
	Baseline	7 LPY	90	-103
	Baseline	3 LPY	53	-71
	Min. Excess Cap./Max. Cap. Factor[15]	3 LPY	42	-46
	Min. Excess Cap./Max. Cap. Factor[15]	7 LPY	72	-68
	Min. Excess Cap./Max. Cap. Factor[15]	10 LPY	89	-76
	50% Higher Capital Costs	10 LPY	168	-171
	50% Lower Capital Costs	10 LPY	57	-61
	50% Lower Non-Fuel O&M	10 LPY	112	-74
	50% Higher Non-Fuel O&M	10 LPY	114	-160
	Low Fuel and Product Prices	10 LPY	113	-132
	High Fuel and Product Prices	10 LPY	113	-99
	NASA/KSC Prices	10 LPY	113	-69
	Commercial LH_2 Prices	10 LPY	113	-49
	Commercial LH_2 Prices	18 LPY	163	-14

(continued)

TABLE B-1. (continued)

Production Technology	Case Description	Capacity	$ Millions (January 1992 $)	
			Total Capital Investment	Net Present Value[2]
Gasification of Coal (continued)	Commercial LH_2 Prices/Min. Excess Cap./ Max. Cap. Factor[15]	10 LPY	89	-8
	Commercial LH_2 Prices/Min. Excess Cap./ Max. Cap. Factor[15]	18 LPY	129	40
Air Separation	Baseline	10 LPY	15	3
	Baseline	7 LPY	12	5
	Baseline	3 LPY	6	8
	Min. Excess Cap./Max. Cap. Factor[15]	3 LPY	5	10
	Min. Excess Cap./Max. Cap. Factor[15]	7 LPY	9	17
	Min. Excess Cap./Max. Cap. Factor[15]	10 LPY	12	16
	50% Lower Capital Costs	10 LPY	8	13
	50% Higher Capital Costs	10 LPY	22	-7
	50% Lower Non-Fuel O&M	10 LPY	15	8
	50% Higher Non-Fuel O&M	10 LPY	15	-1
	Low Electricity and Product Prices	10 LPY	15	5
	High Electricity and Product Prices	10 LPY	15	24
Electrolysis	Baseline	3 LPY	11	-28
	Baseline	7 LPY	21	-42
	Baseline	10 LPY	28	-51
	Min. Excess Cap./Max. Cap. Factor[15]	3 LPY	9	-24
	Min. Excess Cap./Max. Cap. Factor[15]	7 LPY	16	-36
	Min. Excess Cap./Max. Cap. Factor[15]	10 LPY	21	-43
	50% Higher Capital Cost	10 LPY	41	-65
	50% Lower Capital Cost	10 LPY	15	-37
	50% Lower Non-Fuel O&M	10 LPY	28	-40
	50% Higher Non-Fuel O&M	10 LPY	28	-61
	Low Electricity and Product Prices	10 LPY	28	-52
	High Electricity and Product Prices	10 LPY	28	-48
	50% Higher Discount Rate	10 LPY	28	-43
	50% Lower Discount Rate	10 LPY	28	-65
	Commercial LH_2 Prices	10 LPY	28	17
	Commercial LH_2 Prices	7 LPY	21	5
	Commercial LH_2 Prices	3 LPY	11	-7
	Commercial LH_2 Prices/Min. Excess Cap./ Max. Cap. Factor[15]	3 LPY	9	-4
	Commercial LH_2 Prices/Min. Excess Cap./ Max. Cap. Factor[15]	7 LPY	16	11

(continued)

TABLE B-1. (continued)

Production Technology	Case Description	Capacity	$ Millions (January 1992 $) Total Capital Investment	$ Millions (January 1992 $) Net Present Value[2]
COGENERATION/POLYGENERATION				
Wind Turbines/Electrolysis	Baseline	10 LPY/20 MW[16]	165	97
	Baseline	10 LPY/10 MW[16]	128	53
	Baseline	10 LPY/ 0 MW[16]	89	10
	Baseline	7 LPY/ 0 MW[16]	64	-1
	Baseline	7 LPY/10 MW[16]	101	43
	Baseline	7 LPY/20 MW[16]	141	86
	Baseline	3 LPY/20 MW[16]	109	72
	Baseline	3 LPY/10 MW[16]	70	29
	Baseline	3 LPY/ 0 MW[16]	31	-14
	Min. Excess Cap./Max. Cap. Factor[15]	3 LPY/ 0 MW[16]	21	-14
	Min. Excess Cap./Max. Cap. Factor[15]	3 LPY/10 MW[16]	59	29
	Min. Excess Cap./Max. Cap. Factor[15]	3 LPY/20 MW[16]	98	71
	Min. Excess Cap./Max. Cap. Factor[15]	7 LPY/20 MW[16]	124	77
	Min. Excess Cap./Max. Cap. Factor[15]	7 LPY/10 MW[16]	85	32
	Min. Excess Cap./Max. Cap. Factor[15]	7 LPY/ 0 MW[16]	46	-10
	Min. Excess Cap./Max. Cap. Factor[15]	10 LPY/ 0 MW[16]	62	-1
	Min. Excess Cap./Max. Cap. Factor[15]	10 LPY/10 MW[16]	100	42
	Min. Excess Cap./Max. Cap. Factor[15]	10 LPY/20 MW[16]	139	84
Wind Turbines/Air Separation	Baseline	10 LPY/20 MW[16]	138	144
	Baseline	10 LPY/10 MW[16]	84	92
	Baseline	10 LPY/ 0 MW[16]	31	41
	Baseline	7 LPY/ 0 MW[16]	23	30
	Baseline	7 LPY/10 MW[16]	76	82
	Baseline	7 LPY/20 MW[16]	130	133
	Baseline	3 LPY/20 MW[16]	118	120
	Baseline	3 LPY/10 MW[16]	65	68
	Baseline	3 LPY/ 0 MW[16]	11	17
	Min. Excess Cap./Max. Cap. Factor[15]	10 LPY/ 0 MW[16]	22	49
	Min. Excess Cap./Max. Cap. Factor[15]	10 LPY/10 MW[16]	76	100
	Min. Excess Cap./Max. Cap. Factor[15]	10 LPY/20 MW[16]	129	152
	Min. Excess Cap./Max. Cap. Factor[15]	7 LPY/20 MW[16]	124	142
	Min. Excess Cap./Max. Cap. Factor[15]	7 LPY/10 MW[16]	70	90
	Min. Excess Cap./Max. Cap. Factor[15]	7 LPY/ 0 MW[16]	17	39
	Min. Excess Cap./Max. Cap. Factor[15]	3 LPY/ 0 MW[16]	8	18
	Min. Excess Cap./Max. Cap. Factor[15]	3 LPY/10 MW[16]	62	69
	Min. Excess Cap./Max. Cap. Factor[15]	3 LPY/20 MW[16]	115	121

(continued)

TABLE B-1. (continued)

Production Technology	Case Description	Capacity	$ Millions (January 1992 $)	
			Total Capital Investment	Net Present Value[2]
Combined Cycle Turbines/ Coal Gasification	Baseline[3]	10 LPY/20 MW	306	-344
	Baseline[3]	10 LPY/10 MW	239	-266
	Min. Excess Cap./Max. Cap. Factor[15]	10 LPY/20 MW	284	-322
	Min. Excess Cap./Max. Cap. Factor[15]	10 LPY/10 MW	214	-239
	Commercial LH_2 Prices	10 LPY/20 MW	306	-276
	Commercial LH_2 Prices	10 LPY/10 MW	239	-198
	Commercial LH_2 Prices/Min. Excess Cap./ Max. Cap. Factor[15]	10 LPY/10 MW	214	-171
Coal Gasification and Air Separation	Baseline	10 LPY	125	-126
	Baseline	7 LPY	100	-112

[1] Except as noted, all analyses presume a discount rate of 11.75 percent and an inflation rate of 6 percent.

[2] Cumulative net present value of all project cash flows including the total capital investment as a negative cash flow.

[3] Baseline cases for electricity production are able to meet critical launch power demands of 9 MW at an 95% reliability or better.

[4] Single unit cases for electricity production are unable to meet critical launch power demands at the required 95% reliability.

[5] Single unit is presumed in baseline to be able to meet critical launch power demand at the required 95% reliability.

[6] Multiple units (5) are presumed in order to show costs for systems if single units were unable to meet critical launch power demands at the required 95% reliability.

[7] Baseline cases presume baseline cost/economic bases; these systems are unable to meet critical launch power demands at the required 95% reliability.

[8] Average wind speed of 18.4 mph.

[9] Average wind speed of 14.2 mph.

[10] Average wind speed of 12.3 mph.

[11] Discount rate of 18%.

[12] Discount rate of 6%.

[13] Not estimated since pumped hydro is used only to meet critical launch power demands and cash flows other than total capital investment are of much less importance.

[14] LPY = shuttle launches per year.

[15] These systems are not necessarily viable systems for USAF/VAFB since excess capacity is required at VAFB to meet maximum short-term shuttle launch rates. These short-term rates exceed the expected yearly launch rates and thus fundamentally require excess capacity. Alternatives to the baseline concept (which includes excess capacity possibly needed to meet maximum short-term launch rates) include: 1) designing for the expected yearly launch rate with short-term requirements supplied by purchases from commercial producers and 2) operating the baseline system (which includes excess capacity) at its maximum operating rate with excess production sold in commercial markets. The first alternative is considered here by these sensitivity cases. The second alternative is currently less feasible because of weak demands (or excess production capacities) on the West Coast, and because of the presumed disinterest of the USAF to become involved in commercial commodities production.

[16] The reported power capacity is the average net power generated for export rather than the maximum or design capacity which is reported for other cases.